AIR QUALITY

Testimony of Tuan Ngo, P.E.

INTRODUCTION

In this analysis, staff addresses the potential air quality impacts resulting from criteria air pollutant emissions created by the construction and operation of the East Altamont Energy Center (EAEC). Criteria air pollutants are those for which a state or federal standard has been established. They include nitrogen dioxide (NO_2), sulfur dioxide (SO_2), carbon monoxide (CO), ozone (O_3) and its precursors: oxides of nitrogen (NO_x, reported as NO_2), volatile organic compounds (VOC), particulate matter less than 2.5 microns ($PM_{2.5}$) and less than10 microns in diameter (PM_{10}) and their precursors (NO_x, VOC, SO_2), and lead (Pb). Non-criteria air contaminants are addressed in the Public Health section of this document.

The Energy Commission staff evaluated the following major points:

whether the project is likely to conform with applicable Federal, State and the Bay Area Air Quality Management District (District) air quality laws, ordinances, regulations and standards, as required by Title 20, California Code of Regulations, section 1744 (b);

whether the project is likely to cause significant air quality impacts, including new violations of ambient air quality standards or contributions to existing violations of those standards, as required by Title 20, California Code of Regulations, sections 1742.5 and 1742 (b); and

whether the mitigation proposed for the project is adequate to lessen the potential impacts to a level of insignificance, as required by Title 20, California Code of Regulations, sections 1742.5 and 1742 (b).

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

FEDERAL

The federal Clean Air Act requires the proponent of any new major stationary source of air pollution or any major modification to a major stationary source to obtain a construction permit before commencing construction. This process is known as New Source Review (NSR). Its requirements differ depending on the attainment status of the area where the major facility is to be located. Prevention of Significant Deterioration (PSD) requirements apply in areas that are in attainment of the national ambient air quality standards. The NSR requirements apply to areas that have not been able to demonstrate compliance with national ambient air quality standards. The entire program, including both PSD and NSR permit reviews, is referred to as the federal NSR program.

Title V of the federal Clean Air Act requires states to implement and administer an operating permit program. Large sources are required to operate in compliance with the Title V requirements promulgated in Title 40, Code of Federal Regulations, Section 70.

A Title V permit contains all of the requirements specified in different air quality regulations which affect an individual project.

The U.S. Environmental Protection Agency (EPA) has reviewed and approved the Bay Area Air Quality Management District's regulations and has delegated to the District the implementation of the federal PSD, Non-attainment NSR, and Title V programs. The District implements these programs through its own rules and regulations, which are, at a minimum, as stringent as the federal regulations.

The EAEC's gas turbines are also subject to the federal New Source Performance Standards (NSPS). These standards include a NO_x emissions concentration of no more than 75 parts per million (ppm) at 15 percent excess oxygen (ppm@15%O_2), and a SO_x emissions concentration of no more than 150 ppm@15%O_2.

STATE

California Health and Safety Code, Section 41700, requires that: "no person shall discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerate number of persons or to the public, or which endanger the comfort, repose, health, or safety of any such persons or the public, or which cause, or have a natural tendency to cause, injury or damage to business or property."

LOCAL

As part of the Commission's licensing process, in lieu of issuing a construction permit to the applicant for the EAEC, the District prepared and presented to the Commission a Final Determination of Compliance (FDOC) on July 24, 2002. The FDOC evaluates whether and under what conditions the proposed project will comply with the District's applicable rules and regulations, as described below. Staff has incorporated the FDOC recommended conditions of certification in its Final Staff Assessment.

The project is subject to the specific District rules and regulations that are briefly described below:

Regulation 2

Rule 1 - General Requirements. This rule contains general requirements, definitions, and a requirement that an applicant submit an application for an authority to construct and permit to operate.

Rule 2 - New Source Review. This rule applies to all new and modified sources. The following sections of Rule 2 are the regulations that are applicable to this project.

Section 2-2-301 - Best Available Control Technology (BACT) Requirement: This rule requires that BACT be applied for each pollutant which is emitted in excess of 10.0 pounds per day.

Section 2-2-302 - Offset Requirement, Precursor Organic Compounds and Nitrogen Oxides. This section applies to projects with an emissions increase of 50 tons per year or more of organic compounds and/or NO_x. Offsets shall be provided at a ratio of 1.15 tons of emission reduction credits for each 1.0 ton of proposed permitted emissions.

Section 2-2-303 - Offset Requirements, Total Particulate Matter, PM_{10} and Sulfur Dioxide: If a Major Facility (a project that emits any pollutant greater than 100 tons per year) has a cumulative increase of 1.0 ton per year of PM_{10} or SO_2, emission offsets must be provided for the entire cumulative increase at a ratio of 1.0:1.0.

Emission reductions of nitrogen oxides and/or sulfur dioxide may be used to offset increased emissions of PM_{10} at offset ratios deemed appropriate by the Air Pollution Control Officer.

A facility which emits less than 100 tons of any pollutant may voluntarily provide emission offsets for all, or any portion, of their PM_{10} or sulfur dioxide emissions increase at the offset ratio required above (1.0:1.0).

Section 2-2-606 - Emission Calculation Procedures, Offsets. This section requires that emission offsets must be provided from the District's Emissions Bank, and/or from contemporaneous actual emission reductions.

Rule 7-Acid Rain. This rule applies the requirements of Title IV of the federal Clean Air Act, which are spelled out in Title 40, Code of Federal Regulations, Section 72. The provisions of Section 72 will apply when EPA approves the District's Title IV program, which has not been approved at this time. The Title IV requirements will include the installation of continuous emission monitors to monitor acid deposition precursor pollutants.

Regulation 6

Particulate Matter and Visible Emission. The purpose of this regulation is to limit the quantity of particulate matter in the atmosphere. The following two sections of Regulation 6 are directly applicable to this project:

Section 301 - Ringelmann No. 1 Limitation: This rule limits visible emissions to no darker than Ringelmann No. 1 for periods greater than three minutes in any hour.

Section 310 - Particulate Weight Limitation: This rule limits source particulate matter emissions to no greater than 0.15 grains per standard dry cubic foot.

Regulation 9

Rule 1 - Limitations

Section 301: Limitations on Ground Level Sulfur Dioxide Concentration. This section requires that SO_2 emissions shall not impact at ground level in excess of 0.5 ppm for 3 consecutive minutes, or 0.25 ppm averaged over 60 minutes, or 0.05 ppm averaged over 24 hours.

Section 302: General Emission Limitation. This rule limits the sulfur dioxide concentration from an exhaust stack to no greater than 300 ppm dry.

Rule 9 - Nitrogen Oxides from Stationary Gas Turbines. Effective January 1, 1997, this rule will limit gaseous fired, SCR equipped, combustion turbines rated greater than 10 MW to 9 ppm@15%O2.

Regulation 10

Rule 26 - Gas Turbines - Standards of Performance for New Stationary Sources. This rule adopts the national maximum emission limits (40 C.F.R. §60) which are 75 ppm NO_x and 150 ppm SO_2 at 15 percent O_2. Whenever any source is subject to more than one emission limitation rule, regulation, provision or requirement relating to the control of any air contaminant, the most stringent limitation applies.

SETTING

SITE

The project site is located in the northeastern corner of Alameda County and, though physically in the San Joaquin Valley air shed, is subject to the rules of the Bay Area Air Quality Management District. The site is on the eastern slopes of the Diablo Range, one of several coastal mountain ranges bisecting the Bay Area from the northwest to the southeast. The range, from Mt. Diablo at 1312 meters (4305 feet) to the northwest and including Mt Hamilton at 1434 meters (4705 feet) to the southeast, bounds approximately 180 degrees to the southwest of the site. The open and flat San Joaquin Valley (less than 33 meters (100 feet) elevation) bounds the other 180 degrees to the northeast of the project site.

METEOROLOGY AND CLIMATE

The topography of the area varies from rolling hills with relatively flat benches and valleys to steep hills and rugged canyons. The climate of the area is characterized by mild, rainy winters, and warm, dry summers. The mean annual temperature is about 60°F, with the normal seasonal temperature range between 25°F during winter pre-dawn mornings to 110°F on an occasional summer afternoon.

During winter, storms affect the region, attended by southerly or southwesterly winds and short periods of rain. Occasionally, strong northerly surface winds with gusts in excess of 30 meters per second (m/sec) could happen for a day or two during this period. During December and January, fog frequently forms in the San Joaquin Valley and moves over the site.

In summer, air over land is heated by solar radiation more rapidly than air over the cooler Pacific Ocean. This causes land air to rise, developing a circulation which draws ocean air inland. This sea breeze often develops in the afternoon when modified marine air moves through the Altamont pass and enters the area during the summer months. This breeze persists into the evening and occasionally throughout the night, resulting in cool temperatures. If the marine layer is sufficiently deep, ground-hugging clouds could form within several miles of the area's western boundary. The clouds usually dissipate during the afternoon. The sea breeze ranges between 5 to 15 m/sec (11 to 33 mph), but may exceed 20 m/sec (45 mph).

Spring and autumn are typically transitional periods, during which no exceptional meteorological phenomena occur.

Most of the precipitation occurs between October and April, with very little rainfall during the warmer months. The highest and lowest rainfalls on record are 30.8 inches and 5.4 inches, respectively. On the average, the area receives about 14.9 inches annually. The area rarely experiences severe weather, with thunderstorms occurring fewer than ten days per year and hail even less frequently.

The San Joaquin Valley Unified Air Pollution Control District collects meteorological data at the project site. The data collected include wind directions, wind speed, temperature, and atmospheric stability class. The Bay Area Air Quality Management District (District) has determined that the collected meteorological data are representative of the area's meteorology, and that it is appropriate to use for air quality dispersion modeling analysis for this project.

Quarterly and annual wind roses (graphic representations of wind speeds and directions), which were based on data collected in 1999, are shown in Figures 8.1-7 a through g of the AFC (EAEC, 2001a). At the project site, the winds blow predominately from the west from April through September. From October through February, the wind directions are more variable, with winds blowing predominately from the north, southeast and west.

Mixing heights in the area, which represent the altitudes to which different air masses mix together, have been estimated to range from a low of approximately 80 meters (262 feet) in the morning to a high of 2,300 meters (7546 feet) in the afternoon. High mixing heights, normally associated with unstable conditions, can lead to greater dispersion of air contaminants (Smith et al. 1984). Low mixing height and calm wind, in addition to the terrain, can trap air contaminants near the ground.

EXISTING AMBIENT AIR QUALITY

The Federal Clean Air Act and the California Clean Air Act both require the establishment of ambient concentrations of air contaminants called ambient air quality standards (AAQS). The state AAQS, established by the Air Resources Board (ARB), are typically lower (more protective) than the federal AAQS, which are established by the Federal Environmental Protection Agency (EPA). The state and Federal air quality standards are listed in **AIR QUALITY Table 1**. As indicated in **AIR QUALITY Table 1**, the averaging times for the various air quality standards, the times over which they are measured, range from one-hour to an annual average. The standards are read as a concentration, in parts per million (ppm), or as a weighted mass of material per a volume of air, in milligrams or micrograms of pollutant in a cubic meter of air (mg/m^3 and g/m^3).

AIR QUALITY Table 1
Ambient Air Quality Standards

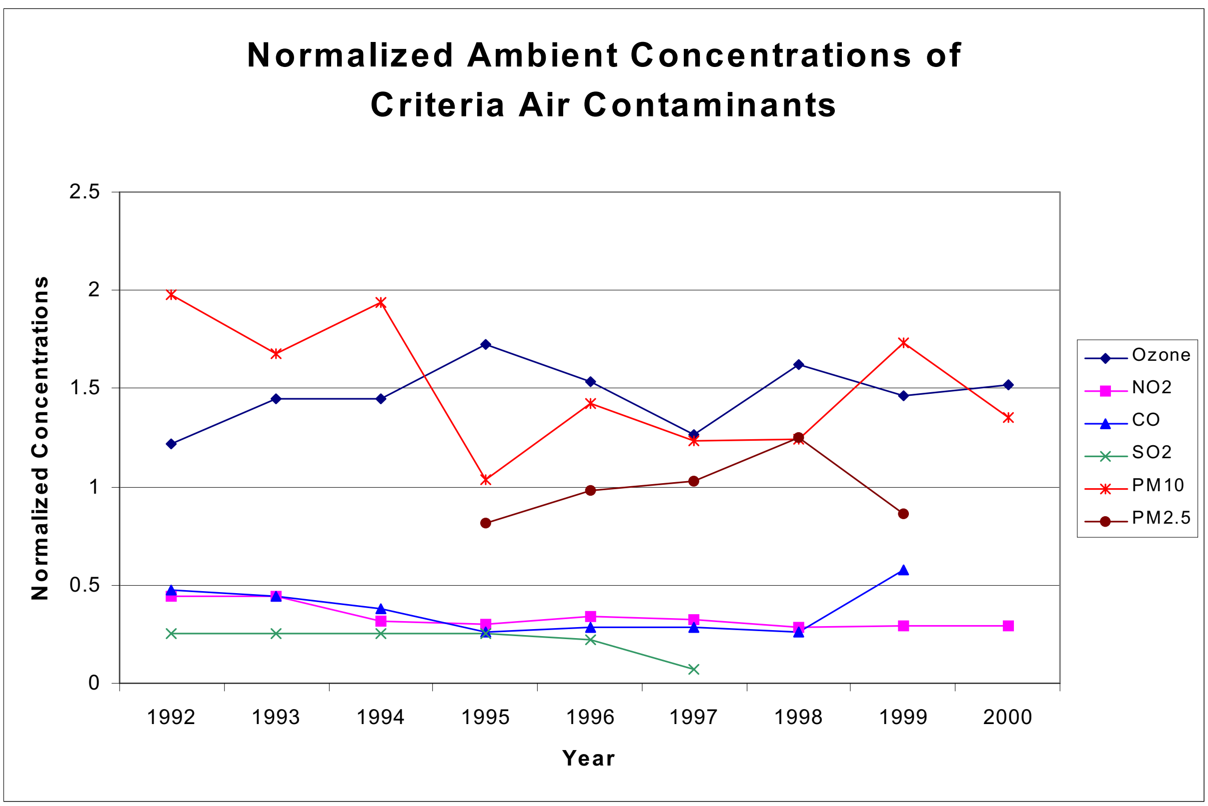
Pollutant	Averaging Time	California Standards	Federal Standards	
			Primary	Secondary
Ozone(O_3)	1-hour	0.09 ppm (180 g/m^3)	0.12 ppm (235 g/m^3)	Same as primary
	8-hour		0.08 ppm (157 g/m^3)	
Particulate Matter (PM_{10})	Annual Geometric Mean	30 g/m^3	---	Same as primary
	24-hour	50 g/m^3	150 g/m^3	
	Annual Arithmetic Mean	---	50 g/m^3	
Fine Particulate Matter ($PM_{2.5}$)	24-hour	No separate standard	65 g/m^3	Same as primary
	Annual Arithmetic Mean		15 g/m^3	Same as primary
Carbon Monoxide (CO)	1-hour	20 ppm (23 mg/m^3)	35 ppm (40 mg/m^3)	None
	8-hour	9 ppm (10 mg/m^3)	9 ppm (10 mg/m^3)	
Nitrogen Dioxide (NO_2)	1-hour	0.25 ppm (470 g/m^3)	---	Same as primary
	Annual Arithmetic Mean	---	0.053 ppm (100 g/m^3)	
Lead(Pb)	30-day	1.5 g/m^3	---	Same as primary
	Cal. Quarter	---	1.5 g/m^3	
Sulfur Dioxide (SO_2)	Annual Arithmetic Mean	---	0.03 ppm (80 g/m^3)	---
	24-hour	0.04 ppm (105 g/m^3)	0.147 ppm (365 g/m^3)	---
	3-hour	---	---	0.5 ppm (1300 g/m^3)
	1-hour	0.25 ppm (655 g/m^3)	---	---
Sulfates	24-hour	25 g/m^3	No federal standard	
H_2S	1-hour	0.03 ppm (42 g/m^3)	No federal standard	

Source: California Air Resources Board

In general, an area is designated as attainment if the concentration of a particular air contaminant does not exceed the standard. Likewise, an area is designated as non-attainment for an air contaminant if that contaminant standard is violated. Where not enough ambient data are available to support designation as either attainment or non-attainment, the area can be designated as unclassified. The unclassified area is normally treated the same as an attainment area for regulatory purposes. An area could be in attainment for one air contaminant while in non-attainment for another, or in attainment for the federal standard and in non-attainment for the state standard for the same air contaminant. The entire area within the boundaries of the air district is usually evaluated to determine the district's attainment status. The Bay Area District includes all or portions of nine counties in the Bay Area: all of San Francisco, San Mateo, Santa Clara, Alameda, Contra Costa, Napa and Marin Counties, and the southwest portion of Solano County and the southern portion of Sonoma County. The air district to the east is the San Joaquin Valley APCD (SJVAPCD).

AIR QUALITY Figure 1 summarizes the historical air quality data near the project location for PM_{10}, CO, SO_2, O_3, and NO_2, measured either to the west in Livermore or the east in Stockton and Fresno (in the SJVAPCD). In **AIR QUALITY Figure 1**, the normalized concentrations represent the ratio of the highest measured concentrations in

AIR QUALITY Figure 1



Notes: CO, NO_2 and ozone data are from the Livermore monitoring station, $PM_{2.5}$ data are from Stockton, and SO_2 data are from the Fresno monitoring station.
Source: Air Resources Board.

a given year to the most stringent applicable national or state ambient air quality standard. Therefore, normalized concentrations lower than one indicate that the measured concentrations were lower than the most stringent ambient air quality standard. Based on the ambient concentration data collected, the area is consistently maintained below the most stringent ambient air quality standards for all criteria pollutants except for PM_{10} and ozone. Below is an in-depth discussion of ambient air quality conditions in the area for ozone, NO_2, CO, and PM_{10}.

Ozone

Ozone is not directly emitted from stationary or mobile sources, but is formed as the result of chemical reactions in the atmosphere between nitrogen oxides and VOC in the presence of sunlight.

Ambient ozone concentrations recorded between 1992 and 2000 have ranged from 11 to 15 parts per hundred million (pphm). The area has experienced 5 to 22 days of violations of the state 1-hr ozone air quality standard every year since 1992. The available ambient ozone data show a slight increasing trend of ozone concentrations since 1992, so there is no clear indication that the ozone air quality is improving.

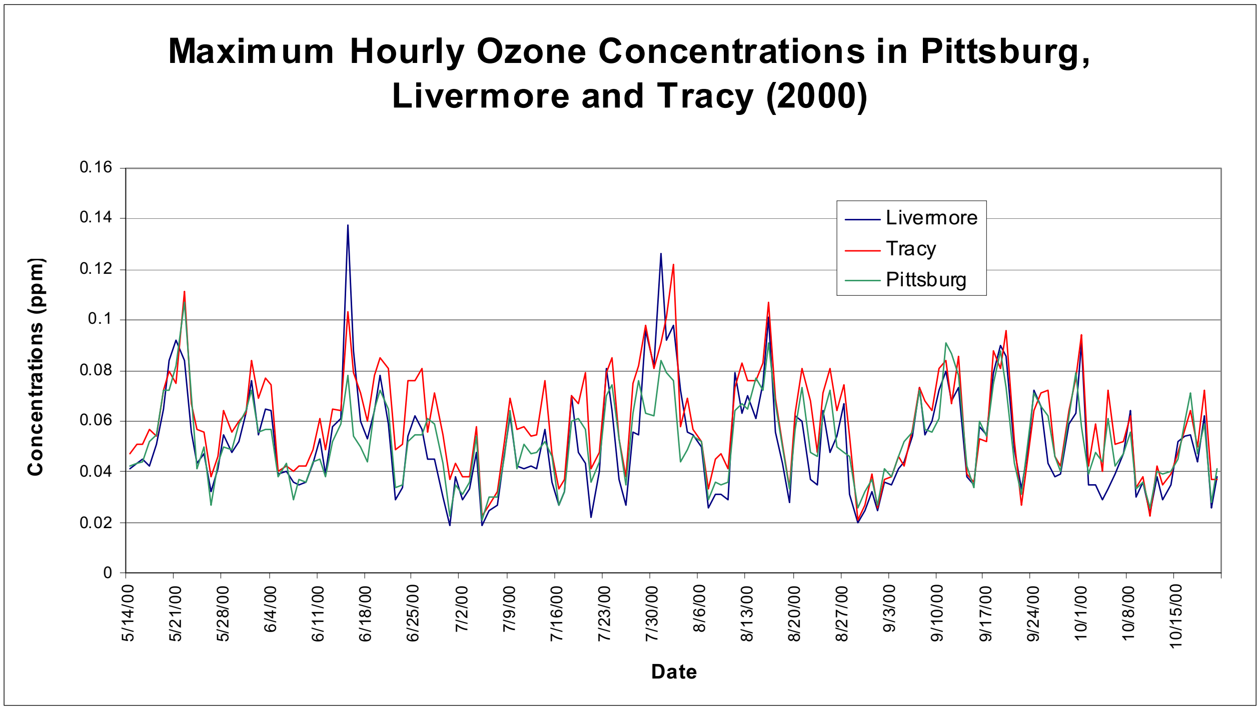
The 8-hour ambient ozone concentration recorded in the area was 9 pphm in 1992 and increased steadily to 11 pphm in 2000. These data indicate that the area would have exceeded the new federal 8-hour ozone standard (8 pphm) every year since 1992. The EPA has established the 8-hour ozone standard, but it has not made a finding that the District would be classified as non-attainment for such standard.

The project, by jurisdiction, is located in the BAAQMD , but is physically located in the San Joaquin Valley Air Pollution Control District (SJVAPCD) air shed. Energy Commission and SJVAPCD staffs believe that the project emissions will significantly affect the San Joaquin Valley air quality. The SJVAPCD has signed Air Quality Mitigation Settlement Agreements with both the EAEC and Tesla[1] project owners stipulating to “the migration of air pollutants” into the San Joaquin air basin “without the corresponding benefits from offsets provided in BAAQMD”. As such, mitigation measures such as emission reduction credits that originate from Antioch, Oakland, San Leandro, Redwood City, and San Jose may not be as effective in reducing the project impacts on ambient air quality as credits located in the San Joaquin Valley.

Because Energy Commission staff believes that the applicant’s proposed Antioch/Pittsburg emission reductions cannot fully mitigate the project’s emission impacts in the local area, staff needs to determine how much more local emission reductions must be provided to reduce the project’s emission impacts to a level of less than significant. Staff reviewed ambient air quality concentrations in the areas of Pittsburg, Livermore, and Tracy to attempt to establish a nexus of transport of air pollution in these three areas.

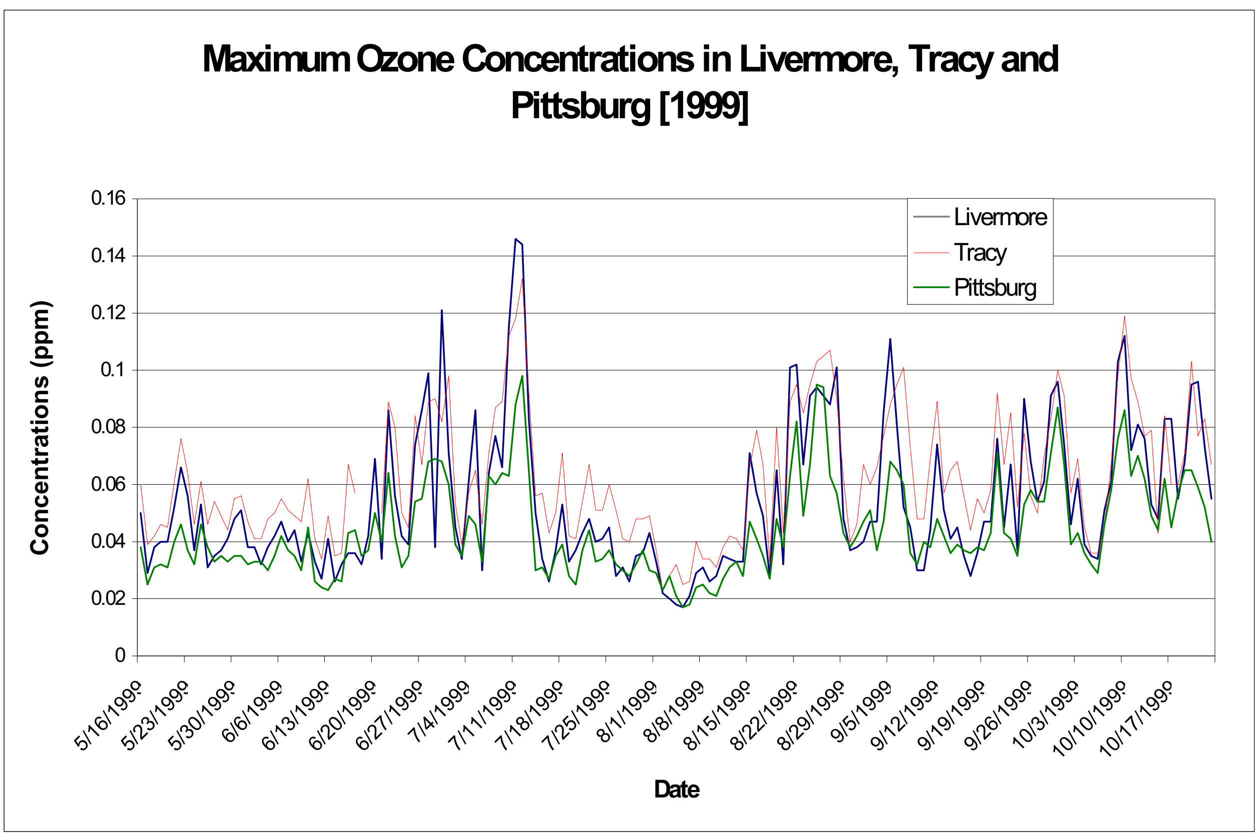
[1] The Tesla Power Project is also located east of Altamont Pass in Alameda County near the San Joaquin county line.

AIR QUALITY Figure 2



<u>Source:</u> Air Resources Board.

AIR QUALITY Figure 3



<u>Source:</u> Air Resources Board.

Staff plotted the ozone concentration data in graphical form in **AIR QUALITY Figures 2 and 3** for the most recent (1999-2000) ozone ambient concentrations for the two consecutive ozone seasons (May-October) for Pittsburg, Livermore, and Tracy. Staff observes that the recorded ozone concentrations in Pittsburg, Livermore, and Tracy behave as if they are all located in the same air basin, i.e., the ozone concentrations peaked and ebbed in a highly correlated relationship almost 95% of the time during the ozone season. Staff also observed that the average ozone concentration in Tracy is 15 percent higher than that in Livermore, and is 30 percent higher than that in Pittsburg. Staff concludes that the air mass experiences a net increase in emissions as it moves from Pittsburg to Tracy. In other words, the emissions generated between Pittsburg and Tracy contribute approximately 30 percent to the area's ozone levels, and the emissions from the Pittsburg/Antioch area contribute approximately 70 percent of the area's ozone levels. Therefore, staff considers that emission reduction credits generated in the Pittsburg/Antioch area would be 70 percent effective in mitigating impacts in the San Joaquin Valley. The remaining 30 percent of the emission reduction credits would offer no appreciate value in mitigating the project's ozone impacts in the San Joaquin Valley.

Staff then analyzed the proposed emission reduction credits located in the Oakland, Redwood City, San Leandro, and San Jose areas. An ARB staff report had studied and performed modeling exercises to establish the impacts of pollutants that are transported from the Bay Area and Sacramento Valley to the San Joaquin Valley on the valley's ozone concentrations (ARB, 1994). The ARB modeling exercises showed that the Bay Area emissions contributed approximately 27 percent to the peak ozone levels in the Valley. Relying on this analysis, staff concludes that 27 percent of the ozone precursor emissions reduction credits proposed by the applicant from the Oakland area mitigate project local, or Northern San Joaquin, impacts during the ozone season (between June to September). SJVAPCD, in the Tesla Power Project Air Quality Mitigation Agreement between the Tesla project owner and the SJVAPCD, also estimates the benefit of BAAQMD ERCs west of Altamont Pass on San Joaquin Valley to be 27 percent. The remaining 73 percent of the BAAQMD emission reduction credits offer no appreciable value as a mitigation measure for the proposed project's ozone impacts in the San Joaquin Valley.

Nitrogen Dioxide

Ambient NO_2 levels measured between 1992 and 2000 are no more than half of the most stringent NO_2 ambient air quality standards, as shown in **AIR QUALITY Figure 1**. Most of the NO_x emitted from combustion sources is in the form of NO, while the balance is NO_2. NO is oxidized in the atmosphere to NO_2, but some level of photochemical activity is needed for this conversion. This is why the highest concentrations of NO_2 occur during the fall and not in the winter, when atmospheric conditions favor the trapping of ground level releases but lack significant photochemical activity (less sunlight). In the summer, the conversion rates of NO to NO_2 are high, but the relatively high temperatures and windy conditions (atmospheric unstable conditions) disperse pollutants, preventing the accumulation of NO_2 to levels approaching the 1-hour ambient air quality standard.

Carbon Monoxide (CO)

The highest CO concentration levels measured between 1992 and 1999 are at least 40 percent lower than the most stringent California ambient air quality standards (see **AIR**

QUALITY Figure 1). The highest concentrations of CO occur when low wind speeds and a stable atmosphere trap the pollution emitted at or near ground level in what is known as the stable boundary layer. These conditions occur frequently in the wintertime late in the afternoon, persist during the night, and may extend one or two hours after sunrise. Since the mobile sector (cars, trucks, and buses) is the main source of CO, we expect ambient concentrations of CO to be highly dependent on its emissions.

Particulate Matter (PM_{10})

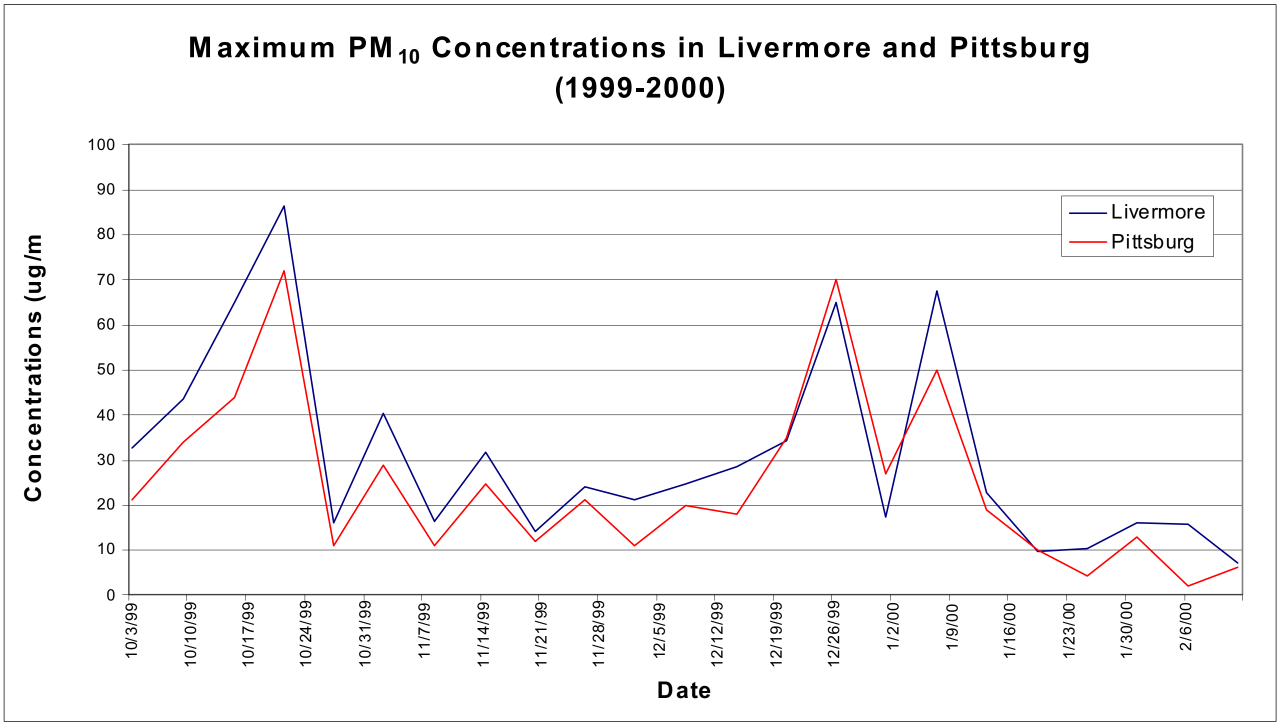
As shown normalized in **AIR QUALITY Figure 1**, PM_{10} concentrations measured near the project site show that the area has experienced violations of the state 24-hour PM_{10} standard every year between 1992 and 2000. During this period, the area experienced between 6 and 30 calculated violation days a year of the state 24-hour PM_{10} air quality standard. The highest PM_{10} concentrations are normally measured between the months of October through February, especially during evening and night hours. During wintertime high PM_{10} episodes, the main contributions of PM_{10} are from wood smoke, combustion of fossil fuels, and entrained dust particles (BAAQMD 2000).

Similar to the reasons discussed in the ozone air quality setting, staff does not believe that the applicant's proposed PM_{10} emission reduction credits fully mitigate the project PM_{10} impact to the local area. To investigate the effectiveness of the proposed PM_{10} mitigation, staff analyzed the PM_{10} ambient air quality between Pittsburg and Tracy. Unfortunately, ambient PM_{10} concentration data for Tracy is not available, so staff used the PM_{10} data for Pittsburg and Livermore, and the previously discussed ozone concentration data to assess the local PM_{10} contribution. **AIR QUALITY Figures 4 and 5** represent the maximum 24-hour PM_{10} concentrations recorded in Pittsburg and Livermore for the two PM_{10} seasons in 1999 and 2000. Staff estimates that the emissions generated in the area between Pittsburg and Livermore contribute approximately 18.4 percent of the PM10 problem.

Due to the lack of PM_{10} concentration data in Tracy, cannot assess the percentage contribution of PM_{10} emissions in the area between Livermore and Tracy. Because of the similarity between the recorded PM_{10} concentration data and the ozone concentration data, staff assumed that the PM_{10} emissions generated in the area between Livermore and Tracy would contribute the same percentage as does the ozone contribution. Using this assumption, staff concludes that the emissions reduction credits from the Pittsburg/Antioch area would be 70 percent effective in mitigating the PM_{10} problem downwind. The remaining 30 percent of the emission reduction credits offer no appreciate value in mitigating the project’s contribution to the area PM_{10} problem.

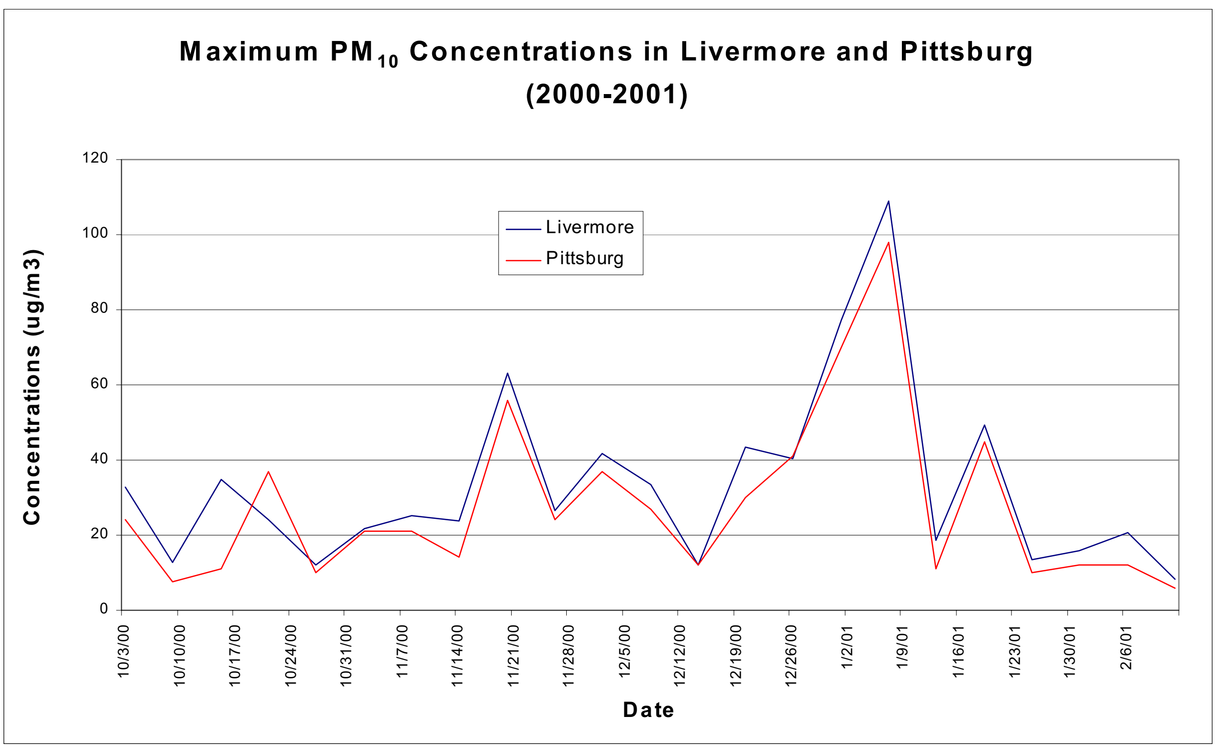
For similar reasons described in the ozone air quality setting, staff believes that 27 percent of the PM_{10} emissions reduction credits from the Oakland, San Leandro, San Jose, and Redwood City areas would mitigate project PM_{10} emission impacts to the local area and the San Joaquin Valley. The remaining 73 percent of the emission reduction credits offer no appreciable value as a mitigation measure for the proposed project’s PM_{10} impacts in the San Joaquin Valley.

AIR QUALITY Figure 4



Source: Air Resources Board.

AIR QUALITY Figure 5



Source: Air Resources Board.

Fine Particulate Matter ($PM_{2.5}$) **Air Quality Figure 6** shows the available $PM_{2.5}$ concentrations measured at various air quality monitoring stations in the Bay area during the period from December 1999 to March 2001. Air Quality Figure 5 shows that the $PM_{2.5}$ concentrations measured in Livermore were among the highest in all the counties of the Bay Area District air basin. [$PM_{2.5}$ ambient concentrations data are not available in the Tracy area, thus the applicant has provided an analysis and used ambient air quality data recorded in the Livermore area as representative of the local area (EAEC, 2001a)].

In a study by the Desert Research Institute (DRI, 1998) for the California Regional PM_{10}/$PM_{2.5}$ Air Quality Study Technical Committee, the following observations can be drawn from ambient concentration data between 1999 and 2001:

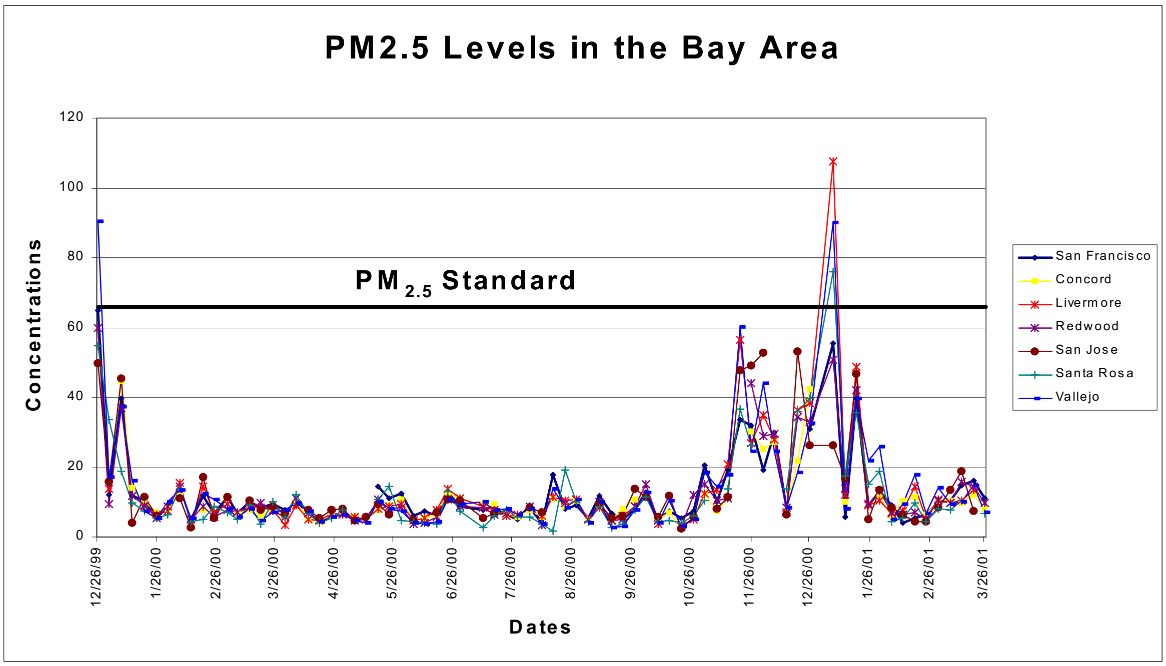
The highest PM_{10} and $PM_{2.5}$ concentrations occur in wintertime (between mid-November to mid-February).

Secondary $PM_{2.5}$ derived from NO_x (ammonium nitrate) is the largest component, often constituting more than 50 percent of $PM_{2.5}$ in urban areas, and higher in non-urban areas.

Organic and elemental carbons are the next largest component, constituting between 25 to 50 percent of $PM_{2.5}$.

Secondary $PM_{2.5}$ derived from SO_x (ammonium sulfate) and fugitive dust constitute the rest of the $PM_{2.5}$.

AIR QUALITY Figure 6



Source: Air Resources Board.

PROJECT EMISSIONS

CONSTRUCTION ACTIVITIES

Construction of the proposed project is expected to last approximately 24 months. Construction generally consists of two major activities: site preparation and installation of major equipment and structures. The applicant provided estimated peak daily and annual construction equipment exhaust emissions (EAEC, 2001a). These estimated construction emissions are identified in Section 8.1E-1 of the AFC and summarized in **AIR QUALITY Table 2**. Staff reviewed the applicant's estimated construction emissions, and believes that they are accurate.

In addition to emissions from construction equipment exhaust, such as vehicles and internal combustion engines, a small amount of hydrocarbon emissions may also occur as a result of the temporary storage of petroleum fuel at the site.

AIR QUALITY Table 2
Construction Emissions

Construction Emission Sources	NO_x	SO_2	VOC	CO	PM_{10}
Daily (lbs/day)	380	10	100	1100	70
Annual (tons/yr)	25	1	6	58	2
Fugitive Dust (tons/yr)					5

Source: EAEC 2001a, AFC, Appendix 8.1E.

PROJECT OPERATION

The project would be built with the following major components:

Three natural gas fired, General Electric (GE) Frame 7FB combustion turbines,

Three heat recovery steam generators (HRSG), each equipped with a 732 MMBTU duct burner,

One steam turbine,

One natural gas-fired 100,000 lbs/hr auxiliary boiler,

One 19-cell cooling tower,

One diesel fueled fire pump, and

One natural gas-fired emergency generator.

Once built, the turbines would be operating in combined cycle mode to produce approximately 1,100 MW of electricity. The applicant proposes to equip each combustion turbine with dry low NO_x combustion technology and a selective catalytic reduction (SCR) system in the HSRG, which together limit the NO_x emissions to 2.5 ppm@15% O_2. To control the CO and VOC emissions, the applicant proposes to equip each combustion turbine/HRSG with a high-temperature oxidation catalyst system, which limits the CO emissions to 6 ppm and the VOC emissions to 2 ppm (EAEC, 2001a).The applicant is requesting that the project be analyzed with the following assumptions:

each turbine/HRSG operates at 8 hours a day without the operation of the duct burner, then

each turbine/HRSG operates at 16 hours a day with the duct burner in operation,

50 cold-starts, 250 hot-starts and 300 shutdowns for both turbines each year (EAEC, 2001a. AFC Appendix 8.1A). A hot start would occur after an overnight turbine shutdown. The applicant states that the duration of a hot start is approximately one hour, and as much as three hours for a cold start (EAEC, 2001a).

The applicant also requests that the project emissions include the emissions from the natural gas-fired auxiliary boiler. The auxiliary boiler is expected to operate about 8 hours a day and no more than 3,000 hours annually (EAEC, 2001a).

The emergency generator and the diesel fire pump are expected to operate only when the turbines are not in operation; therefore, their normal operation emissions are not to be included in the total emissions of the facility. However, either piece of equipment can be tested on any one day for a period no longer than 1 hour (EAEC, 2001a). Therefore, the emissions from testing of these two pieces of equipment will be included in the facility's total emissions.

The applicant provided staff with their estimates of the facility's hourly, daily, and annual emissions (EAEC, 2001a AFC Appendix 8.1A). Staff has asked for manufacturer's information to substantiate the applicant's estimated emissions; however, because the project is still in the conceptual phase, much of the requested information is preliminary or not available. These include the specifications and emissions guarantee for the turbine, the duct burner, the auxiliary boiler and their control systems. The applicant eventually provided some preliminary emissions data for the turbines, and the SCR system emissions guarantee for the turbine/HRSG power train (EAEC, 2001c).

Staff evaluated the applicant's emissions estimates and believes that they have been underestimated, especially for the turbine start-up and shut down emissions. In response to a staff data request, the applicant provided some preliminary data from GE, which indicated that the turbine's uncontrolled, steady state emissions are higher than the applicant's provided start-up emissions (EAEC, 2001c). A turbine's start-up emissions are generally higher than the uncontrolled, steady state operation emissions. Therefore, staff had to re-estimate the total facility emissions to determine the project's emission impacts and possible mitigation.

AIR QUALITY Table 3 lists the staff's estimated project emission profile for the facility during periods of cold start, hot start and steady state operation. The applicant estimates that each turbine/HRSG power train will emit approximately 80 pounds of NO_x, 840 pounds of CO, and 16 pounds of VOC each hour for each cold or hot start. The applicant also estimates that each cold start would last 3 hours, and each hot start would last one hour.
The East Altamont facility would employ three-GE frame 7FB turbines. Because the start-up emissions data for the FB turbine are not available, staff has used the start-up

emissions data, provided by GE, for another facility with a similar configuration [three gas turbines, combined cycle with auxiliary boiler]. This similar facility uses three GE frame 7FA turbines and has guaranteed NO_x emissions of 9 ppm without the use of SCR (Appendix A). Because the EAEC proposed turbines (7FB model) are larger, staff has linearly adjusted the start-up NO_x and VOC emissions upward to reflect the higher uncontrolled emissions of the FB model turbine.

For example, the GE-provided NO_x and VOC emissions for cold start-up for the three-frame 7FA, combined cycle facility (at 9 ppm) are 80 lbs and 67 lbs per hour, per turbine, respectively. Because the proposed FB model gas turbines have higher NO_x emissions (25 ppm), staff adjusted the EAEC start-up NO_x and VOC emissions by a factor of 25 divided by 9, or 2.78. Thus, the EAEC start up NO_x and VOC emissions would be 220 lbs and 180 lbs per hour per turbine, respectively, during the period of cold start.

Using the same approach, staff estimated that EAEC NO_x and VOC emissions during the period of hot start would be 200 lbs and 180 lbs per hour, respectively.

It should be noted that the applicant underestimated the times for cold start and hot start as well. According to GE, a start-up for a similar configuration facility (also equipped with auxiliary boiler) could last 4 hours for cold start, and 1.5 hours for hot start (Appendix A).

The staff and the applicant's estimated daily and annual emissions from the project are shown in **AIR QUALITY Table 4**. The table shows different operating scenarios and the resultant emissions, including CTG startup (cold and hot), shutdown, and steady state operation.

In **AIR QUALITY Table 4**, staff has assumed 4-hours duration for each cold start, and 1.5-hours duration for each hot start. Staff also estimated the expected emissions using the applicant's request of 50 cold starts and 250 hot starts, 5,100 hours steady state operation with duct burners, and the rest (3,085 hours) steady state operation without the use of duct burners.

The applicant has requested and agreed to conditions that would restrict the facility's annual emissions to the levels presented in the last row of **AIR QUALITY Table 4**.

AIR QUALITY Table 3
Power Train Emissions Estimates

Start-up emissions (Staff estimates)	**NO_x**	**SO_2**	**PM_{10}**	**VOC**	**CO**
Cold (total emissions for 4 hours, lbs)	2,640	N/A	N/A	2,160	3,350
Hot (total emissions for 90 minutes, lbs)	900	N/A	N/A	810	1,350
Start-up emissions (Applicant estimates)					
Cold (total emissions for 3 hours, lbs)	720	N/A	N/A	48	2,514
Hot (total emissions for one hour, lbs)	240	N/A	N/A	16	902
Steady state @ 100% load (Applicant estimates) (lbs/hr)	71	22	55	20	104

AIR QUALITY Table 4
Project Daily and Annual Emissions

Operational Profile	NO_x	SO_2	PM_{10}	VOC	CO
3 turbine cold-start, hot start and steady state operation (maximum daily) (lbs/day)[1]	4,830	450	1,220	3,320	16,020
Maximum steady state daily operation (lbs/day)[2]	1,730	450	1,220	480	2,550
Maximum annual emissions including start ups and shutdown[1,3] (tons/year)	443	86	216	219	1,150
Maximum permitted annual emissions including start ups and shutdown[4] (tons/year)	263	24	148	74	794

Notes:
1 Staff estimated.
2 EAEC, 2001a. AFC Table 8.1A-8.
3 Assume 4 hr for each cold start, 1.5 hr for each hot start, 5100 hrs. steady state with duct burner and 3085 hrs. at steady state without duct burner.
4 These are the permitted annual emissions limits, including all start up and shut down events, that the facility shall not exceed.

INITIAL COMMISSIONING

Initial commissioning refers to a period of approximately 60 days prior to beginning commercial operation when the combustion turbines undergo initial test firing. During this commissioning phase, the project may operate at a low-load for a period of time for fine-tuning. The District typically requires that each activity of the commissioning period be planned carefully, and that all NO_x and CO emissions and the time of commissioning be minimized to lessen the impacts from the turbines, duct burners and HRSG. It should also be noted that the NO_x and CO emissions during the commissioning period are not higher than emissions during normal start-up or operation of the facility; therefore, staff expects no new impacts from the NOx and CO emissions during the commissioning period. All criteria air contaminant emissions during the commissioning period will be counted toward the annual emission limits; thus there is an incentive for the applicant to limit the commissioning period to the shortest time possible.

CLOSURE

Eventually the facility will close, either as a result of the end of its useful life, or through some unexpected situation, such as a natural disaster or catastrophic facility breakdown. When the facility closes, then all sources of air emissions would cease to operate and thus all impacts associated with those emissions will no longer occur. The only other expected emissions would be fugitive particulate emissions from the dismantling activities. These activities will be short term and will create fugitive dust emissions levels much lower than those created during the construction of the project. Dismantling activities, although short term, could be similar to those of construction because of demolition, equipment tailpipe emissions, and fugitive dust from re-grading. Staff recommends that a facility closure plan be submitted to the Energy Commission Compliance Project Manager to demonstrate compliance with applicable District Rules and Regulations during closure activities.

AMMONIA EMISSIONS

Due to the large combustion turbines used in this project and the need to control NO_x emissions, significant amounts of ammonia will be injected into the flue gas stream as part of the SCR system. Not all of this ammonia will mix with the flue gases to reduce NO_x; a portion of the ammonia will pass through the SCR and will be emitted unaltered, out of the stacks. These ammonia emissions are known as ammonia slip. The applicant has committed to an ammonia slip no greater than 10 ppm (EAEC, 2001a). On a daily basis, a 10 ppm slip is equivalent to approximately 2,500 pounds per day of ammonia emitted into the atmosphere from the East Altamont Energy Center facility.

IMPACTS

Air dispersion models provide a means of predicting the location and magnitude of the air contaminant impacts of a new emissions source at ground level. These models consist of several complex series of mathematical equations, which are repeatedly calculated by a computer for many ambient conditions. The model results are often described as a unit of mass per volume of air, such as micrograms per cubic meter (g/m^3). They are an estimate of the concentration of the pollutant emitted by the project that will occur at ground level.

The applicant has used an EPA-approved ISCST3 model to estimate the impacts of the project's NO_x, PM_{10}, CO and SO_x emissions resulting from project construction and operation. A description of the modeling analyses and results are provided in Section 8.1.5 and Appendices 8.1B and 8.1E of the AFC (EAEC, 2001a). The applicant's modeled impacts were added to the available highest ambient background concentrations measured from 1997 to 2000 at the Tracy or Livermore monitoring stations. Staff then compared the results with the ambient air quality standards for each respective air contaminant to determine whether the project's emission impacts would cause a new violation of the ambient air quality standards, or contribute to an existing violation.

Inputs for the modeling include stack information (exhaust flow rate, temperature, and stack dimensions), specific turbine emission data, and meteorological data such as wind speed, atmospheric conditions, and site elevation. For this project, the meteorological data used as inputs to the model included hourly wind speeds and directions measured at the project site.

CONSTRUCTION IMPACTS

The applicant provided staff with a modeling analysis of the project's operating emissions impacts from directly emitted pollutants, which they believe demonstrates that no significant impacts will be caused by the construction of the project. Staff reviewed the applicant's modeling analysis and concludes that it is adequate.

The results of the project construction impacts analyses are presented in **AIR QUALITY Table 5**. The modeling analyses included both the fugitive dust and vehicle exhaust emissions, which include PM_{10}, NO_x and CO. In **AIR QUALITY Table 5**, the first and second columns list the air contaminant, i.e., NO_2, PM_{10}, and CO, and the averaging time for each air contaminant analyzed. The third and fourth columns present the project emission impacts and the highest measured concentration of the criteria air contaminants in the ambient air (background), respectively. The fifth column presents the total impact, i.e., the sum of project emission impact and background measured concentration. The sixth column presents the most restrictive ambient air quality standard for such air contaminant. The seventh column presents the percentage of the total impacts in relation to the most restrictive ambient air quality standards.

AIR QUALITY Table 5
Facility Maximum Construction Impacts

Pollutant	Avg. Period	Project Impact (g/m^3)	Background (g/m^3)	Total Impact (g/m^3)	State Standard (g/m^3)	Percent of Standard
NO_2	1-hr.	285	149	434	470	90
CO	8-hr.	152	3236	3386	10,000	35
PM_{10}	24-hr.	30[1]	87	117	50	230

Source: EAEC, 2001a, AFC Table 8.1E-5.
1. Staff estimated.

As indicated in **Air Quality Table 5**, the project construction activities would further exacerbate existing violations of the state 24-hour PM_{10} standard, and thus constitute a significant air quality impact for PM_{10}. The project's construction activities would not create a new violation of either NO_2 or CO air quality standards, thus those impacts are not considered significant.

Construction of the facility would result in unavoidable short-term PM_{10} impacts. Because the area is non-attainment for PM_{10}, additional impacts during construction of the project can be viewed as significant. However, it is doubtful that the general public would be exposed to the construction impacts associated with the project. Staff reviewed the modeling files and believes that the likely PM_{10} construction impacts during the day would be in the range of 20 to 30 g/m^3. Nevertheless, because the area PM_{10} standard is already violated, the construction of the project would exacerbate the existing violation. Therefore, the project's construction PM_{10} emission impact is significant.

Staff believes that the PM_{10} impacts from the construction of the project can be mitigated with the implementation of the staff recommended construction mitigation measures, as discussed in the **Mitigation** section.

OPERATION IMPACTS

The applicant provided staff with a modeling analysis of the project's operating emissions impacts from directly emitted pollutants, which they believe demonstrates that no violations of ambient air quality standards will be caused by the operation of the project. Staff reviewed the applicant's modeling analysis and concludes that it is adequate.

AIR QUALITY Table 6 presents the results of the modeling analysis using worst case hourly emissions, which include turbine start-up emissions as presented in **AIR**

QUALITY Table 4. **AIR QUALITY Table 6** shows that, with the exception of PM_{10}, the project does not cause any new violations of any applicable air quality standard listed in the table, and thus those impacts are not significant. As for PM_{10}, staff believes that the project itself will contribute to existing violations of the state 24-hour PM_{10} air quality standard. That standard is based on the protection of public health and includes a margin of safety to protect sensitive members of the population. Thus, project emissions that contribute to existing violations of that standard have the potential to exacerbate public health problems associated with existing ambient PM concentrations (please see Attachment A to staff's **Public Health** analysis). Staff therefore views the project's PM_{10} emissions and associated impacts as significant.

AIR QUALITY Table 6
Facility Operation Emission Impacts on Ambient Air Quality

Pollutant	Avg. Period	Project Impact (g/m^3)	Background (g/m^3)	Total Impact (g/m^3)	Most Restrictive Standard (g/m^3)	Percent of Standard
NO_2	1-hour (start up)	236	149	385	470[1]	80
	1-hour (steady-state)	20	149	169	470[1]	36
	Annual	0.6	28	28.6	100[2]	30
SO_2	1-hour	20	40	60	650[1]	10
	24-hour	2	27	29	105[1]	10
CO	1-hour	690	5,940	6,630	23,000[1]	30
	8-hour	180	3,230	3,410	10,000[1]	35
PM_{10}	24-hour	7	87	93	50[1]	190
	Annual	0.6	23	23	30[1]	80

Notes: All short-term (1-hour) ambient air quality impacts have been modeled as the impacts dominated by the emergency generator or diesel fired pump emissions during periods of testing. All long-term (8-hour, 24 hour and annual) impacts are the impacts from the project caused by normal operations.
[1] State standard [2] Federal standard Source: EAEC, 2001a. Table 8.1-29.

CUMULATIVE IMPACTS

To evaluate the direct emission impacts of the East Altamont Energy Center along with other probable future projects, staff needs specific information that is included when project applicants file a permit application with the District. Projects located up to six miles from the proposed facility usually need to be included in the analysis. Staff believes that the direct emissions from any project located beyond six miles of EAEC would not affect the cumulative modeling analysis. The District indicated that there is no source that has received a permit to construct, which needs to be included in the cumulative impact analysis.

There are two other energy facilities [Tesla Power Plant by Midway Power, and Tracy Peaking Power Plant by GWF] proposed to be built and operated within six miles of the proposed project. In addition, a new town (Mountain House) of approximately 10,000 acres will be built adjacent to the proposed facility.

The Mountain House Environmental Impact Report (EIR) concludes that, among other impacts, the development of the new town would increase emissions of NO_x, VOC, SO_x and PM_{10}. All of these would contribute to the existing violations of ozone and PM_{10} standards in the San Joaquin Valley and the San Francisco air basins, and thus will interfere with the progress toward attainment of the above air quality standards. The San Joaquin County Board has approved the development of the new town with overriding considerations of unmitigated significant impacts to air quality.

Because the development of the new Mountain House community would result in a significant impact to air quality, the addition of new emission sources would further worsen that impact. Staff believes that under certain meteorological conditions, such as when the wind is calm and the weather is hot, the emissions from all three proposed power plants combined with the emissions from the development of the Mountain House community could cause a significant cumulative air quality impact.

SECONDARY POLLUTANT IMPACTS

Secondary air contaminants are those that are not directly formed in, or emitted from, the stacks of the equipment such as the project's turbines, boiler or emergency engine. These air contaminants are formed outside of the stacks as a result of chemical reactions involving the directly emitted pollutants. For example, ozone can be formed by photochemical reactions between NO_x and VOCs in the presence of sunlight in the atmosphere.

Ozone impacts

The proposed project's NO_x and VOC emissions can contribute to the formation of ozone. There are air models that can be used to quantify ozone impacts, but they are only appropriate for use in regional air quality planning efforts where numerous sources are input into the model to determine the regional ozone impacts. There are no regulatory agency models approved for assessing single source ozone impacts. However, because of the known relationship of NO_x and VOC emissions to ozone formation, staff believes that the emissions of NO_x and VOC from the East Altamont facility have the potential to contribute to higher ozone levels if not mitigated.

Secondary PM_{10} impacts

The project's NO_x, VOC, NH_3 and SO_x emissions can contribute to the formation of secondary PM_{10}, namely organics, nitrates, and sulfates.

Not all hydrocarbons can form secondary PM_{10}. Hydrocarbons with six or less carbon atoms in the chain will not participate in the formation of the carbon based PM_{10}. The project's VOC emissions will be in the form of unburned natural gas, which contains only one to two carbon atoms in the chain. Thus, the turbine exhaust is not expected to emit any significant amount of VOC that can participate in the formation of secondary PM_{10}.

Staff believes that the project's ammonia emissions could contribute to the formation of ammonium nitrate in the area, potentially worsening violations of the state 24-hour PM_{10} standard. Available research (Spicer, 1982) indicates that the conversion of NO_x to nitrate is approximately between 10 and 30 percent per hour in a polluted urban area where ozone and ammonia are present in sufficient amounts to participate in the reaction. Staff assumed a 30 percent NO_x to nitrate conversion rate (the upper end of the conversion rate based on the area's continuing ozone violations and worsening trend) as well as a linear extrapolation of the project's PM_{10} modeling results. Staff estimates the maximum NO_x to nitrate impact from the project to be 4 g/m^3. Because the area is non-attainment for the state 24-hr PM_{10} and possibly the federal 24-hour $PM_{2.5}$ standards, the ammonium nitrate contribution, although small, would be significant. Staff believes that the ammonia slip from the turbine/HRSG exhausts should be reduced to 5 ppm (from the proposed 10 ppm) to lessen the contribution of ammonium nitrate to the local area.

Concerning sulfates as PM_{10}, staff believes that the project's SO_2 emissions will contribute to sulfate levels in the area, although in a very small amount. Currently, there are no agency (EPA or CARB) recommended models or procedures for estimating sulfate formation. The applicant has conducted an analysis to quantify the potential for SO_2 to convert to particulate matter. This analysis is based on the ambient air quality conditions and the emissions in the San Joaquin Valley, which they believe represent the conditions at the project site. The results of this analysis indicate that up to 50 percent of the project's SO_2 emissions can potentially be converted to particulate matter [in the form of sulfates]. Similar analyses were performed in other siting cases in the Bay Area (Los Medanos, Delta Energy Centers) indicating that the potential conversion of SO_2 to particulate matter could be as high as 35 percent.

Using a conservative 35 percent conversion of SO_2 to particulate matter, the project's SO_2 emissions are expected to add an impact equivalent to as much as 30 tons of particulate matter per year. Because the area is non-attainment for the state 24-hour PM_{10}, and possible non-attainment for the federal 24-hr $PM_{2.5}$ air quality standards, the project's SO_2 emissions can potentially contribute to the existing violations of the standards. Therefore, its SO_2 emissions contribution is significant. Staff believes that local offsets, in the form of emission reductions, should be provided to lessen the project's particulate matter contribution to the ambient air to a level of insignificance.

VISIBILITY IMPACTS

The applicant has provided, as part of their PSD application to the District, a visibility impact analysis, which shows that the project is not expected to exceed any significant visibility impairment increment inside any nearby PSD Class I areas (EAEC, 2001a). Class I areas are areas of special national or regional value from a natural, scenic, recreational, or historic perspective. The District's issuance of the FDOC indicates that the visibility impact analysis is adequate.

APPLICANT'S PROPOSED MITIGATION

CONSTRUCTION PHASE

The applicant proposes that it would implement Best Available Control Measures (BACM) during construction of the project. These measures are listed below:

Frequent watering of unpaved roads and disturbed areas (at least twice a day).

Limit speed of vehicles on the construction areas to no more than 10 MPH.

Employ tire washing and gravel ramps prior to entering a public roadway to limit accumulated mud and dirt deposited on the roads.

Treat the entrance roadways to the construction site with soil stabilization compounds.

Place sandbags adjacent to roadways to prevent run-off to public roadways.

Install windbreaks at the windward sides of construction areas prior to the soil being disturbed. The windbreaks shall remain in place until the soil is stabilized or permanently covered.

Employ dust sweeping vehicles at least twice a day to sweep the public roadways that are used by construction and worker vehicles.

Sweep newly paved roads at least twice weekly.

Limit equipment idle times (no more than five minutes).

Employ electric motors for construction equipment when feasible.

Apply covers or dust suppressants to soil storage piles and disturbed areas that remain inactive for over two weeks.

Pre-wet the soil to be excavated during construction.

Employ oxidizing soot filters on all large suitable off-road construction equipment with an engine rating of at least 100 bhp.

Employ construction equipment that can be feasibly electrified to reduce its exhaust.

In addition, the applicant will maintain the construction emissions so that fugitive emissions will be limited by District rules to a maximum 20 percent opacity during any three-minute span. Because the construction emissions are short-term, the applicant has not proposed any emission reduction credits to offset the new emissions. Staff will include requirements in the conditions that these control measures also apply to the construction of the linear facilities.

OPERATION PHASE

The applicant proposes to mitigate the emission increases from the proposed facility using a combination of clean fuel, emission control devices and emission reduction credits (EAEC, 2001a). Control devices include dry low-NO_x combustion design, SCR and oxidation catalyst technology for each of the combined cycle turbine trains to minimize their NO_x, VOC and CO emissions. The proposed control devices are designed to maintain the turbine/duct burner emissions to 2.5 ppm NO_x, 6 ppm CO, and 2 ppm VOC, over a 1-hour period (EAEC, 2001a). The ammonia slip emissions (from unreacted ammonia in the SCR) are proposed to be maintained at 10 ppm or less. Natural gas will be the only fuel used, which will minimize the project's PM_{10} and SO_x emissions. Below is a brief description of the emission control technologies that East Altamont Energy Center will employ.

Dry Low- NO_x Combustors

Over the last 20 years, combustion turbine manufacturers have focused their attention on limiting the NO_x formed during combustion. Because of the expense and efficiency losses due to the use of steam or water injection in the combustor cans to reduce combustion temperatures and the formation of NO_x, CTG manufacturers are presently choosing to limit NO_x formation through the use of dry low- NO_x technologies. In this process, firing temperatures remain somewhat low, thus minimizing NO_x formation, while thermal efficiencies remain high.

Flue Gas Controls

To further reduce the emissions from the combustion turbines before they are exhausted into the atmosphere, flue gas controls, primarily catalyst systems, will be installed in the HRSG. The applicant is proposing two catalyst systems: a selective catalytic reduction system to reduce NO_x, and an oxidizing system to reduce CO and VOC.

Selective Catalytic Reduction

Selective catalytic reduction (SCR) refers to a process that chemically reduces NO_x by injecting ammonia into the flue gas stream, over a catalyst, in the presence of oxygen. The process is termed selective because the ammonia reducing agent preferentially reacts with NO_x rather than oxygen, producing inert nitrogen and water vapor. The performance and effectiveness of SCR systems are related to operating temperatures, which may vary with catalyst designs. Flue gas temperatures from a combustion turbine typically range from 950 to 1100^{o}F.

Catalysts generally operate between 600 to 750^{o}F (ARB 1992), and are normally placed inside the HRSG where the flue gas temperature has cooled. At temperatures lower than 600^{o}F, the ammonia reaction rate may start to decline, resulting in increasing ammonia emissions, called ammonia slip. At temperatures above about 800^{o}F, depending on the type of material used in the catalyst, damage to some catalysts can occur. The catalyst material most commonly used is titanium dioxide, but materials such as vanadium pentoxide, zeolite, or a noble metal are also used. These newer catalysts (versus the older alumina-based catalysts) are resistant to fuel sulfur fouling at temperatures below 770^{o}F (EPRI 1990).

Regardless of the type of catalyst used, efficient conversion of NO_x to nitrogen and water vapor requires uniform mixing of ammonia into the exhaust gas stream. Also, the catalyst surface has to be large enough to ensure sufficient time for the reaction to take place.

The applicant proposes to use a combination of dry low-NO_x combustor technology and an SCR system to produce a maximum NO_x concentration exiting the HRSG stack of 2.5 ppm, corrected to 15 percent excess oxygen averaged over a 1-hour period. The District, in its FDOC, has required that the maximum NO_x concentration is to be maintained at 2.0 ppm (BAAQMD, 2002c).

Oxidizing Catalyst

To reduce the turbine CO and VOC emissions, the applicant proposes to install an oxidizing catalyst similar in concept to catalytic converters used in automobiles. The catalyst is usually coated with a rare metal, such as platinum, which will oxidize unburned hydrocarbons and CO to water vapor and carbon dioxide (CO_2). The CO catalyst is proposed to limit the CO concentrations to 6 ppm at 15 percent O_2. The District, in its FDOC, has required that the maximum CO concentration is to be maintained at 4.0 ppm (BAAQMD, 2002c).

OFFSETS

The proposed facility is required by the BAAQMD to provide offsets on an annual basis (tons per year (tpy)) for NO_x, VOC, and PM_{10} as shown in **AIR QUALITY Table 7**. The applicant has provided some emission reduction credits, in the form of District issued banking certificates, for 305 tpy of NO_x, 87.5 tpy of VOC, and 2.2 tpy of PM_{10}. In addition, the applicant will provide 444 tons of SO_2 emission reduction credits to mitigate the project's 148 tons per year of PM_{10} emissions.

The applicant has not provided emission offsets for the new SO_2 emission increases from the proposed East Altamont Energy Center facility because the District has not required it to do so.

ADEQUACY OF PROPOSED MITIGATION MEASURES

CONSTRUCTION PHASE MITIGATION

As mentioned earlier in the impact section, construction of the project would cause PM_{10} emissions that would add to the existing violations of the ambient PM_{10} air quality standard. Therefore, staff concludes that the project PM_{10} emission impacts due to construction of the project are significant. As a result, staff is proposing Conditions of Certification **AQ-SC1** through **AQ-SC4** that would require the project applicant employ measures designed to further control project and linear construction-related emissions. Staff believes that the implementation of these mitigation measures would reduce project and linear construction-related impacts to a level less than significant.

AIR QUALITY Table 7
Maximum Annual NO_2, VOC, and PM_{10} Emissions and District Offset requirements

Pollutant	New Emissions from EAEC (tpy)	Offset Ratio for BAAQMD[1]	Offsets Required by BAAQMD[1] (tpy)	Offsets proposed by Calpine (tpy)
NO_2	263	1.15:1	302	***305*** (Calpine)
VOC	74	1.15:1	85	***87.5*** (Calpine)
PM_{10}	148	3:1 SO_2:PM_{10}	444	***444*** (Calpine)
SO_2	24[2]	N/A	0	***0***

Notes: 1 Offset ratio as required by the BAAQMD.
2 Staff estimates project's SO_2 emissions using an annual average of 0.28 gr. of sulfur/100 scf natural gas.

OPERATIONAL PHASE MITIGATION

The project will be built using BACT (clean burning using natural gas, SCR and CO oxidation catalyst systems) in accordance with the District NSR.

The proposed project would add 263 tpy of NO_x, 74 tpy of VOC, 148 tpy of PM_{10}, and 24 tpy of SO_2 to the San Joaquin Valley air shed. The applicant has proposed to provide 305 tpy of NO_x, 87.4 tpy of VOC, and 444 tpy of SO_2 emission reduction credits, in the form of the Bay Area District issued banking certificates, as offsets. These banking certificates were issued for emission reductions in San Leandro (certificates #645, 687), Redwood City (#716), Oakland (#602, 662), San Jose (#661), and Antioch (#741, 749). These proposed emission offsets are consistent with the Bay Area District NSR rule, but because of the distance between the source of offsets and the proposed facility, the proposed offsets may not fully mitigate the project impacts on the local ambient ozone and PM_{10} air quality. As staff has discussed in the **SETTING** section, additional local ozone precursors (NO_x and VOC) and PM_{10} emission reduction credits need to be provided to lessen the facility local impact to a level of less than significant. **AIR QUALITY Table 8** represents staff's estimate of the equivalent effectiveness of the applicant's proposed emission reduction credits in reducing the project impacts to the local area and the valley. In the same table, staff also presents the amount of emissions reduction credits to be secured in the area to mitigate the project to a level of less than significant. According to staff estimates, the applicant would need to secure 133 tpy of NO_x, 42 tpy of VOC, and 50 tpy of PM_{10} local emission reduction credits.

To arrive at the equivalent effectiveness values of the applicant’s proposed emission reduction credits, staff referred to several studies: the ARB staff's study of the potential effect of pollutants from the Bay Area on the San Joaquin Valley, the staff analysis of the ambient air quality recorded in Pittsburg/Livermore/Tracy areas; and the San Joaquin District Air Quality Mitigation Agreement with Florida Power and Light for the Tesla project. In that agreement, the SJVAPCD staff used an average effectiveness for the Bay Area’s emission reduction credits west of Altamont Pass of 27 percent.

As mentioned in the **SETTING** Section, the ARB has concluded that Bay Area air contaminants contribute approximately 27 percent to the San Joaquin Valley’s peak ozone level. Thus, emission reduction credits from the general Bay Area can be said to be 27 percent effective in mitigating the project impacts. The remaining balance of 73 percent has to come from the local area.

AIR QUALITY Table 8
Staff Estimated Additional Local Emission Reductions

	Face Values of Credits from the Bay Area (tpy)				Equivalent Effectiveness[1] (tpy)			
Certificate Number, Location	NO_2	VOC	PM_{10}	SO_2	NO_2	VOC	PM_{10}	SO_2
645, 687 San Leandro	108	44	0	0	29	12	0	0
716 Redwood City	12	0	1	0	3	0	0	0
602, 662 Oakland	76	41	0	46	21	11	0	12
741, 749 Antioch	110	0	0	437	77	0	0	306
661 San Jose	0	32	0	0	0	9	0	0
Total	305	117	1	483	130	32	0	318
Project Emissions					263	74	148	24
Excess or <Shortfall>					<133>	<42>	<148>	294[2]
Additional emission reductions needed (tons)					**133**	**42**	**50**[3]	**0**

Notes:

1 The equivalent effectiveness means the emission reduction credits that can effectively mitigate the project's impacts. For the credits in Antioch, staff has assigned 70% effectiveness, while those credits in Oakland, San Leandro, Redwood City and San Jose were assigned a 27% effectiveness (see SETTING Section).

2 There are 294 tons per year of excess SO_2 that can be used for inter-pollutant trading for PM_{10} at a ratio of 3 to 1.

3 There are 50 tons per year of PM_{10} that need to be secured after the use of excess SO_2 as inter-pollutant trading for PM_{10} , i.e., using an inter-pollutant trading ratio of 3:1, 294 tpy of SO_2 is equivalent to 98 tpy of PM_{10}.

As mentioned in the **SETTING** Section, staff evaluated the recorded ambient concentrations of ozone and PM_{10} in the Pittsburg/Livermore/Tracy areas, and concluded that 70 percent of the ozone and PM_{10} emissions generated in the Pittsburg/Antioch area contribute to ambient ozone and PM_{10} levels in the Livermore/Tracy area. Thus, the emission reduction credits from the Pittsburg/Antioch area can be said to be 70 percent effective in mitigating the project impacts. Again, the remaining balance of 30 percent should come from the local area.

After applying each of the appropriate effectiveness ratios mentioned above, the equivalent effectiveness emissions reductions were adjusted and entered in **AIR QUALITY Table 8**.

The difference between the project emissions and the equivalent emission reduction credits shows either a mitigation shortfall, or excess. These values are presented in the next to last row of **AIR QUALITY Table 8**. This row shows that the project would experience a shortfall of 133 tpy of NO_2, 42 tpy of VOC, and 148 tpy of PM_{10}. This row also shows that the project would experience an excess of 294 equivalent tpy of SO_2 emission reduction credits.

The applicant proposes to use the excess SO_2 emission reduction credits to inter-pollutant trade for PM_{10}, at a ratio of 3 pounds of SO_2 for every pound of new PM_{10} emission. The applicant has provided 294 tpy of SO_2 emission reduction credits, which, using the above ratio, is equivalent to 98 tpy of PM_{10}. The project PM_{10} emissions would be 148 tpy, thus the project would still experience a shortfall of 50 tpy of PM_{10} as indicated in the last row of **AIR QUALITY Table 8**.

The applicant and the SJVAPCD have jointly reached in concept to an "Air Quality Mitigation Agreement," patterned after a similar agreement for the Tesla Power Project, to address the potential transport of project emissions to the San Joaquin Valley. This agreement is in a conceptual stage, and will need approval by the San Joaquin Valley Air Pollution Control Board to be in effect.

According to the SJVAPCD staff, the Tesla "Air Quality Mitigation Agreement" would require the applicant to pay a "Mitigation Fee" that the SJVAPCD would use to create air quality benefits in the valley. Although the agreement's stated preference is that the program would generate benefits within the Northern Region of the AQMD, particularly within or near the City of Tracy, there is no guarantee that the emission reductions would be generated in the local area. The fee could be used for bus retrofitting/replacement, lawnmower replacement, or retrofit/replacement of heavy-duty internal combustion engines. The quantity, schedule, and permanence of emission reductions that could occur via such an agreement are not specified.

Staff has serious concerns about the vagueness of the above agreement, especially about the locations and the amount of actual emission reductions that would be generated using the settlement funds. The agreement mentions that funding would be used to generate reductions from retrofitting or replacing buses, replacing lawnmowers, and/or replacing or retrofitting internal combustion engines. However, the proposal does not identify specific vehicle fleets, engines, or locations of specific controls that would be implemented, or the quantities of emission reductions that would occur. Staff needs to identify specific mitigation measures so that we can determine whether those mitigation measures actually would lessen or eliminate the proposed project's impacts.

Mitigation measures (such as providing fees for unspecified air quality mitigation purposes) that are not tied to specific action plans may not be adequate or effective in reducing project related impacts. In general, an agency cannot rely on a mitigation measure of unknown efficacy in concluding that a significant impact will be mitigated to a less than significant level. In order for staff to reasonably conclude that impacts will be mitigated to less than significant, any mitigation measure must include realistic performance standards or criteria that will ensure the mitigation of the significant effects. In order to rely on a mitigation plan, staff needs to possess meaningful information reasonably justifying an expectation of compliance. Staff regards meaningful information to include:

a clear explanation of the measure's objectives (an accounting of the emissions reductions to be provided by the implementation),

a description of specific measures designed to provide the necessary reductions, how the implementation will occur, who is responsible for the implementation, where the implementation will occur, the timetable for implementation, and measures to verify performance.

In the absence of such information, staff cannot reasonably be assured that the SJVAPCD and applicant agreement has a high likelihood of mitigating the project impacts.

Notwithstanding the above mitigation agreement, the applicant has submitted a list of "consensus" mitigation measures, which combines measures suggested by the Commission staff, the applicant and the SJVAPCD (EAEC, 2002sss). The measures consist of:

1. Providing natural gas transit buses, and a natural gas refueling station to the Tracy Regional Transit. These buses will be used to transport the passengers from the Tracy, Mountain House, and Livermore areas to the BART station in Livermore. The purpose of this measure is to reduce the number of single drivers and their vehicles commuting to San Francisco.
2. Replacing the diesel school buses with newer, natural gas school buses to reduce the students' exposure to diesel exhaust.
3. Installing solar panels at the Mountain House School to provide active demonstration of local generation and load reduction.
4. Renovation of the Mountain House School parking lot to reduce fugitive dust and relieve traffic congestion at the school.
5. Providing an ultra-low sulfur diesel refueling station for construction equipment at the new Mountain House community to reduce the equipment's SO_2, PM_{10} and VOC emissions.
6. Providing funding to subsidize the cost of replacing of old wood stoves with newer, EPA certified units to reduce PM_{10} and VOC emissions
7. Providing funding to subsidize the cost of retrofitting fireplaces with natural gas to reduce PM_{10} and VOC emissions.
8. Providing funding to retrofit or replace heavy-duty on-road, or agriculture engines to reduce NO_x and PM_{10} emissions.

The applicant has offered an analysis of the potential emission reductions and the cost-effectiveness of each of the above individual mitigation measures (EAEC, 2002sss). The analysis shows the cost effectiveness for the above mitigation measures ranges from $4,000 to as high as $280,000 per ton of NO_x or PM_{10} reduced. Of the above mitigation measures, the measures that are most cost effective and which have the greatest potential for emission reductions are the replacement of wood stoves ($3,900 per ton), the retrofit of fireplaces with gas logs ($7,500 per ton), and the retrofit/replacement of heavy-duty engines ($13,000 per ton).

STAFF RECOMMENDED ADDITIONAL MITIGATION

CONSTRUCTION PHASE

To adequately mitigate the remaining significant impacts associated with project and linear construction, staff is proposing a number of Conditions of Certification (**AQ-SC1** through **AQ-SC4**). These conditions include requirement for the identification of a Compliance Mitigation Manager who will be responsible for enforcement of construction mitigation measures. The recommended mitigation measures include that the applicant submit a comprehensive Fugitive Dust Mitigation plan, the submittal of monthly compliance reports, the use of catalyzed diesel particulate filters on construction equipment, the use of ultra low sulfur diesel fuel for that equipment, the use of newer equipment that meets the EPA and/or CARB 1996 or better off-road equipment emission standards, and limiting diesel engine idle time to no more that 10 minutes.

Staff believes that, with the implementation of these mitigation measures and the compliance responsibilities for monitoring by the Compliance Mitigation Manager, any remaining project and linear construction related impacts would be reduced to a level of insignificance.

OPERATION PHASE

While the applicant has provided emission reduction credits (ERCs) sufficient to satisfy the Bay Area District rules and regulations (see District Final Determination of Compliance), the ERCs do not, in staff's opinion, fully mitigate the project PM_{10} and ozone impacts to the local area. Staff believes that the applicant needs to provide additional local ozone precursor reductions and PM_{10} emission reductions to mitigate the project impacts to a level of less than significant. As mentioned earlier, staff recommends that additional local emission reductions equal to 175 tpy of ozone precursors (NO_x and/or VOC), and 50 tpy of PM_{10} emission reductions be secured in the Tracy/Livermore area (see **AIR QUALITY Table 8**) to mitigate the project. These emissions reductions would be in addition to those required by BAAQMD rules.

Staff evaluated the information provided by the applicant in their "consensus" proposal and found that the most cost effective measures contained in that proposal that also have the potential to provide sufficient emission reductions were the heavy duty engine retrofit/replacement program and the wood stove replacement program (EAEC, 2002sss). Staff recommends that a combination of wood stove replacements and heavy-duty engine retrofit/replacements be implemented to achieve the emission reductions in the local area. Below is staff's detailed discussion of the recommended mitigation measures.

Additional Ozone Precursors (NO_x and/or VOC) Mitigation

The SJVAPCD currently sponsors a program called the "Heavy-Duty Engine Incentive Program," which provides financial incentives to any individual or business to purchase new engines or retrofit existing units that would lower emissions. Under this program, the SJVAPCD provides a maximum $13,000 for each ton of NO_x emissions reduced. According to the SJVAPCD, from its start in 1997 to June, 2002, the program has achieved approximately 22,450 tons of NO_x emission reductions from a combination of engine retrofits and engine replacements, totaling approximately 3,466 engines. Most of these engines are in agricultural services, with some engines used off-road (such as construction equipment), and some on-road vehicle applications. The lifetime for each engine funded through the Engine Incentive Program varies from 7 to 12 years depending the application, and the average lifetime is 7.7 years (SJVAPCD's 2002 and 2005 Rate of Progress Plan, May 2002).

Staff recommends, as the preferred mitigation option, that the applicant provide funding to SJVAPCD to continue and expand this program. The only restriction that staff recommends would be that the funding only be used for applications that would result in emission reductions in the Livermore/Tracy and northern San Joaquin Valley areas.

Because the engine incentive program can generate emission reductions that only have an average 7.7 years lifespan, while the proposed project could last up to 40 years, staff estimated the number of participating engines necessary to ensure mitigation for the entire project life. To do so, staff estimated the entire project's NO_x and VOC emission (shortfall) liability, and then estimated the potential emission reductions for each engine. The project's NO_x and VOC shortfall has been estimated above to be 175 tpy multiplied by 40 years, which is 7,000 tons for the entire project life.

Using the SJVAPCD's estimated emission reductions of 22,450 tons for 3,466 engine applications, staff estimates that each engine would generate about 6.5 tons of NO_x emission reduction credits over its lifetime (7.7 years life). Thus, 1,080 engines need to be retrofitted (or replaced) to mitigate the project's lifetime NOx and/or VOC liability of 7,000 tons.

Staff recommends that the applicant provide enough funding to the SJVAPCD to support retrofit/replacement of 1,080 engines over four consecutive 8 year-phases. Altogether, this mitigation measure would provide 7,000 tons of NO_x emission reductions, which would provide continuing mitigation for the lifetime of the EAEC. **AIR QUALITY Table 9** summarizes staff's findings and recommendations for the additional mitigation measures.

Additional PM_{10} Mitigation

The SJVAPCD has not published the estimated PM_{10} emission reductions for the engine incentive program; however, the applicant has provided some information from the SJVAPCD and estimates that the heavy-duty engine incentive program can generate up to 53 lbs each year for each participating engine (EAEC, 2002sss).

Using the applicant's information, staff estimates that approximately 57,240 pounds per year (29 tpy) of PM_{10} emission reductions can be generated from retrofitting/replacement of 1,080 heavy-duty engines. This amount of emission reductions would reduce the project PM_{10} emissions liability to 21 tpy.

Taking into account that the area typically experiences violations of the PM_{10} standard only during the four winter months (November to February), staff recommends that only the four month portion of the project's remaining PM_{10} emissions liability (21 tpy) be mitigated with additional local PM_{10} emission reductions.

Using this approach, staff estimates that the project's remaining PM_{10} emissions liability that needs to be mitigated is [(4/12)x21 tpy], or 7 tons of PM_{10} per PM_{10} season.

To mitigate the project's remaining PM_{10} emissions, staff recommends that the applicant develop a plan to provide financial incentives to willing participants in the Livermore/Tracy area to replace their current conventional wood stoves with newer, cleaner units. Under this program, each participant would receive a cash rebate of $1,250 to replace his or her current wood stove with a newer, EPA certified unit. [This program is currently being offered in another project (Three Mountain Power Plant) and is very successful]. Staff estimates that the program should provide enough funds (approximately $490,000) to subsidize 395 units. Staff estimates that this program would generate 7 tons of PM_{10} per PM_{10} season to mitigate the remaining PM_{10} emission liability for the project (see **AIR QUALITY Table 9**).

AIR QUALITY Table 9
Project's Emissions and Staff Recommended Additional Mitigation

	NO_X and/or VOC	**PM_{10}**
Annual Project Emission Liability	175 tons per year	50 tons per year
Lifetime Project Emission Liability (for 40 years)	7,000 tons	not calculated
Heavy-Duty Engine Incentives Program		
Phase 1 (2002-2010) – 270 engines	1,725 tons	29 tons per year
Phase 2 (2011-2018) – 270 engines	1,725 tons	29 tons per year
Phase 3 (2019-2026) – 270 engines	1,725 tons	29 tons per year
Phase 4 (2027-2034) – 270 engines	1,725 tons	29 tons per year
Total for all 4 phases – 1,080 engines	7,000 tons	
Remaining Project Liability	0	21 tons per year, 7 tons per PM_{10} season
Wood Stove Replacement Program – 395 units	Not calculated	7 tons per PM_{10} season
Adequate to mitigate project's emissions?	Yes	Yes

Note: [1] N/C means not calculated

Additional SO_x and Secondary PM_{10} Mitigation

In addition to the Wood Stove Replacement program, staff also recommends that ultra low sulfur diesel fuel, which contains no more than 15 ppm sulfur content be used to fuel the operation of the fire pump diesel engine. Because the operation of the fire pump engine is sporadic, staff has not estimated its SO_x emissions. However, the operation of the engine with ultra low sulfur diesel fuel would result in 97 percent SO_x emission reduction compared with standard diesel fuel (which contains up to 500 ppm sulfur) each and every time the engine is in operation. [This ultra low sulfur fuel is already proposed to be used in the construction of the facility]. Staff believes that the slight different cost between the ultra low sulfur diesel and the standard diesel would be a feasible control measure to reduce sulfur oxides emissions, and secondary PM_{10} emissions that the fire pump diesel engine produced.

What if neither program works?

Staff believes that the implementation of both programs above would generate enough ozone precursors and PM_{10} emission reductions to mitigate the project's local contribution to the area's ozone and PM_{10} violations. However, for numerous reasons, there is the potential that participation in the engine and woodstove replacement programs could be insufficient, resulting in emission reduction shortfalls.

For example, the continuity of the engine replacement program could be complicated by the fact that the State Air Resources Board has already issued regulations that affect the emissions of heavy-duty engines (on- or off-road) as soon as 2004. These regulations may affect the availability of qualified engines as newer, cleaner engines would not be able to participate in the replacement/retrofit program.

The woodstove program relies on private consumers deciding that the subsidy is adequate to proceed with a "home remodeling." These remodeling decisions are subject to arbitrary and volatile factors such as housing prices and home equity, the state of the economy, and consumer confidence. Participation in the woodstove replacement program therefore cannot be guaranteed.

The applicant could also acquire Emission Reduction Credits (ERCs) to make up emission reduction shortfalls due to insufficient engine and woodstove replacement participation. Alternatively, the applicant could choose to secure all the necessary emission reductions in the form of credits. The SJVAPCD has offset banks split into three regions: the North, Central and Southern regions. If the applicant were to secure ERCs in lieu of or in combination with staff's proposed mitigation programs, staff recommends that the applicant acquire NO_x, VOC, and PM_{10} emission reduction credits,in the North Region of the SJVAPCD. Staff believes that ERCs from North Region of SJVAPCD, equal to the amount specified in **AIR QUALITY Table 9**, would be closest to the proposed project and to the areas of potential impacts.

Staff believes that there are adequate ERCs available in the SJVAPCD offset bank to fully mitigate the project's NO_x, VOC and PM_{10} emissions. From the standpoint of flexibility, the applicant could agree to any combination of actual emission reductions from the replacement programs in the northern San Joaquin valley and the acquisition of ERCs as long as the quantities equal the amounts shown as necessary in **AIR QUALITY Table 9.**

In summary, staff believes that the project's potential air quality impacts can be adequately mitigated through the use of controlling emissions from existing sources (i.e., engines and woodstoves) and/or the use of ERCs acquired from the SJVAPCD offset bank. Staff would prefer that all feasible actual emission reduction scenarios be explored first and that when those scenarios are exhausted or are not deemed feasible, then any remaining emissions shortfall be met through the acquisition of ERCs from the SJVAPCD offset bank.

WHAT IF THE EAEC PROJECT WAS SUBJECT TO SJVAPCD RULES?

As noted in the **SETTING** section, the proposed project site is located in the northeast corner of Alameda County on the east side of the Altamont Pass, and is subject to the jurisdiction of the Bay Area Air Quality Management District. However, due to local topography, the proposed site and project emissions would be located in the San Joaquin Valley air shed, which is subject to oversight by the SJVAPCD (jurisdiction begins at the San Joaquin County line, a mile east of the project site). As such, the project emissions would affect the air quality in the San Joaquin Valley, especially the northern portion of the air basin, due to its unique location. The air quality in the San Joaquin Valley is worse than the air quality in the Bay Area. That is why the SJVAPCD offset requirements are stricter than those of the Bay Area District. [The stricter offset requirements are intended to ensure that the SJVAPCD can achieve progress toward its attainment goal.]

To demonstrate that staff's proposed mitigation is appropriate and reasonable for the proposed location of the project, staff developed a scenario wherein the proposed project is subject to the rules of SJVAPCD, the region most affected by the project and its emissions. Staff then compared those SJVAPCD offset requirements with the Staff additional mitigation proposed above. Staff evaluated the offset requirements for the EAEC project using SJVAPCD Rule 2201 - New and Modified Stationary Source Review. The evaluation included the offset threshold and used the following offset ratios:

1.2:1 for emission reductions that are within 15 miles of the proposed project site, and

1.5:1 for those reductions that are outside of the 15 miles radius, including those offsets in BAAQMD.

Additionally, the ERCs from the BAAQMD west of Altamont Pass were valued at a 27 percent effectiveness to offset San Joaquin Valley projects and emissions (per CARB and SJVAPCD).

As shown in **AIR QUALITY Table 10**, if the project were subject to the jurisdiction of the SJVAPCD, the applicant would need to provide an additional 216 tpy of NO_x and VOC as ozone precursors reductions and an additional 95 tpy of PM_{10} reductions. These additional emission reductions are similar, but greater than what staff is proposing (175 tpy of ozone precursor and 50 tpy of PM_{10} emission reductions) in order to mitigate the impacts of the project's emissions in the San Joaquin Valley. The differences stem from staff valuing those BAAQMD credits from Antioch for NO_x and SO_x at 70 percent effectiveness, while staff assumed that the SJVAPCD would value all credits west of Altamont Pass, including those in Antioch, at 27 percent effectiveness (see **AIR QUALITY Table 8**). Additionally, some of differences are due to the relative stringency of the SJVAPCD rules compared to BAAQMD due to the poor San Joaquin Valley regional air quality and limited progress towards attainment, and the SJVAPCD Rule 2201 Offset Threshold.

AIR QUALITY Table 10
EAEC Project per SJVAPCD Rules and w/BAAQMD ERCs

	VOC	NO_x	PM_{10}	SO_x
EAEC Project Emissions (tpy)	73.7	263	148.0	24
SJVAPCD Rule 2201 Offset Threshold (tpy)	10	10	14.6	27.4
SJVAPCD Offsets required	63.7	253	133.4	0.0
BAAQMD ERCs	116.7	306.4	0.7	482.8
Transport ratio (CARB's and SJVAPCD's 27%)	3.7	3.7	3.7	3.7
SJVAPCD Distance ratio	1.5	1.5	1.5	1.5
Combined ratio (per SJVAPCD)	4.2	4.2	4.2	4.2
Value of BAAQMD ERCs (@ combined ratio of 4.2:1)	27.8	72.9	0.2	115.0
Net surplus (shortfall) (tpy)	-35.9	-180.1	-133.2	115.0
SOX for PM10 (@ interpollutant trading ratio of 3.0:1)			38.3	
Total ozone precursor shortfall (tpy)	-216			
Net surplus (shortfall) (tpy)	**-216**		**-94.9**	**0**

ENVIRONMENTAL JUSTICE

Staff has reviewed Census 2000 information that shows the minority population is less than fifty percent within a six-mile radius of the proposed East Altamont Energy Center facility, and Census 1990 information that shows the low-income population is less than fifty percent within the same radius. However, there is one census block that lies north and northeast of the proposed site, which contains more than fifty percent minority members. Since all project impacts would be mitigated to less than significance if staff's recommended mitigation measures are implemented, there is no environmental justice issue.

RESPONSE TO PUBLIC AND AGENCY COMMENTS

PUBLIC COMMENTS

G&DK-9 *School bus route is on both Kelso and Mountain House Road bordering the plant. Students will be exposed to high volume of pollution on a daily basis.*

Response: Because of the close proximity with the facility, students are expected to be exposed to a certain level of air pollution during certain weather conditions. Based on the collected weather data, these conditions could happen approximately a few days per year. The applicant will be required to provide mitigation to the emissions increases from the proposed power plant, thus the short term exposure to these events can be reduced to a level of less than significant.

G&DK-14 *The project mayaffect the air quality in San Joaquin Valley. It is not clear what consideration has been given to the impacts on the air quality in the valley.*

Response: Staff is recommending that all emissions from the project be mitigated with emission reduction credits that not only meet the criteria of the District Air Quality rules, but would be effective to reduce the facility impacts to a level of less than significant, even in the San Joaquin Valley. These mitigation measures include NO_x, VOC and local PM_{10} and SO_2 emission reduction credits.

MS-6 *The PSA has pointed out that Calpine is not proposing BACT air emissions controls for the plant. Again, unconscionable in an area with severe air quality problems to begin with. In addition to air pollution impacts on the San Joaquin Valley, this will add to the air pollution problems in the downwind Sierra Nevada Mountain region.*

Response: Even though Calpine is not proposed to operate the facility with emission limits that are comparable with BACT, the staff of the Bay Area Air Quality Management District and staff recommend that the facility would operate at levels comparable to BACT. These recommendations include a 2 ppm NO_x emission concentration, 5 ppm ammonia slip, and an oxidation catalyst.

EG-2 *Calpine will pollute our local area while the San Joaquin Pollution people will spend our mitigation money in Bakersfield. They already screwed us with the Peaker Plant. How many of these plants are we going to get. Offsetting their pollution with credits from industries shut down 10 years ago doesn't help no matter where the ERC's are located. The SJVAPCD is selling out Tracy once again.*

Response: As presented in the Staff Recommended Additional Mitigation, staff has made recommendations that additional mitigation measures be implemented to generate actual emission reductions in the local area. Staff believes that these emission reductions would mitigate the project's impacts to the air quality in the area.

EIH-1 *I am offended that Calpine has reneged on their promise to mitigate the impact of their plant on the citizens of Tracy. They now propose to give the funds to the Pollution Control District. I do not trust the Pollution Control District to use the funds for our protection.*

Their actions on the GWF project proves my theory. Every indication from their efforts on this project show their poor judgment.

Response: Staff is not aware that Calpine has made any promise to mitigate the project's impacts in Tracy area. Regardless of their promise, staff believes that the implementation of staff recommended additional mitigation (see above) would mitigate the project's impacts to a level of less than significant.

PS-1 *It's ironic that the San Joaquin Valley Air Pollution Control District is asking for money to mitigate EAEC Pollution because the emission reduction credits are up to 60 miles away from the plant site. The ERC's provided by the SJVAPCD to* *mitigate the Tracy Peaker Plants emissions were predominately 200 miles away. The San Joaquin Pollution District will sell out the citizens of Tracy out just like they did in the Tracy Peaker Plant. They will probably spend the $965,000 to fix up their office in Fresno. I attended the EAEC Workshop in Tracy and found the District representative to be very arrogant. Didn't he realize that without the CEC staff the district would receive no mitigation. The only local mitigation we got from GWF was through our own citizens negotiating. Calpine is using the Pollution Control District to ruin any real local air quality mitigation that the CEC might force them to provide. They are just trying to avoid their obligation to offset their local emissions in the Tracy area. Deny them their license.*

<u>Response:</u> Staff does not suggest criticism of the SJVAPCD or its staff. The District's mission and priority are slightly different from those of the Energy Commission. Energy Commission staff analyzes the development of the EAEC facility as a single project, while the District staff analyzes the project to fit the program, to ensure that it would comply with applicable laws, and to ensure that the project will not interfere with progress toward attainment for the whole area. Because of different goals and priorities, the District and the Commission staff seem to ask the applicant different questions; however, we have the same goal of protecting the public at large.

PRB-1 *I respectfully request that the California Energy Commission require the Calpine Company (East Altamont project) to mitigate all of its air quality credits in Tracy. Allowing this company to clean up other areas of the San Joaquin Valley will do absolutely nothing to clean the air in our local Tracy. Ground level ozone is becoming an increasing health hazard that our community is having to endure.*

Please enforce the strictest mitigation possible to this business. It is my request that in our current grade of poor air quality, labeled "extreme" by the U.S. Environmental Protection Agency, that this project be denied.

<u>Response</u>: As mentioned earlier, staff has recommended the state-of-the-art control technology, and local mitigation measures be implemented to mitigate the project impacts.

CBJ-1, AKJ-1, JSS-1 *We forward three articles regarding health impacts by pollution in the valley to the Commission staff for review.*

<u>Response:</u> Staff thanks you for your articles. We have reviewed the articles and incorporated appropriate findings into staff recommendations for mitigation in Air Quality and Public Health of this report.

AGENCY COMMENTS

San Joaquin County Board of Supervisors comments that the project will create negative impacts on air quality in the local area, and that the proposed emission reduction credits, which the applicant acquired from the Bay Area, may not be sufficient to mitigate such impacts.

Response: Staff agrees with the San Joaquin Board of Supervisors comment, and has recommends mitigation measures to specifically address the proposed facility impacts to the local air quality. Staff recommended mitigation measures are discussed in detail in the Staff Recommended Additional Mitigation section.

COMPLIANCE WITH LORS

FEDERAL

The applicant has submitted to the District an application for the Federal PSD permit. The District issued a Final Determination of Compliance (FDOC) on July 24, 2002, which includes the demonstration of compliance with the federal PSD requirements. [However, the final PSD permit will not be issued until the applicant has demonstrated compliance with the Federal Endangered Species Act.] Staff has incorporated the District's recommended Conditions into the Final Staff Assessment.

In addition, the applicant is required to submit an application to the District for a significant revision to the existing Major Facility Review Permit (Title V) prior to commencing operation. The applicant is also restricted from commencing operation unless a Title IV Permit has been issued, or 24 months after submitting an acid rain application (Title IV) to the District, whichever is earlier. Compliance with both of these Federal titles will be determined at a later date.

STATE

As discussed earlier and summarized below, the project has the potential to cause significant ozone and particulate matter impacts. Staff cannot recommend licensing the project without implementation of staff's recommended local mitigation measures [heavy-duty engine incentives and replacement of wood stoves]. If these two recommendations are adopted, staff believes that the project impacts on ozone and PM_{10} would be mitigated to a level of less than significant.

LOCAL

The District has issued a FDOC (July 24, 2002), which states that the proposed project is expected to comply with all applicable District rules and regulations, and that offsets will be provided prior to the issuance of the project Authority to Construct permit.

CONCLUSIONS

1. The project has the potential to cause significant impacts to the state and federal 1-hour and the federal 8-hour ozone air quality standards in both the Bay Area and San Joaquin air basins.
2. The project has the potential to cause significant impacts to the state 24-hour PM10 and the federal 24-hour PM2.5 air quality standards in both the Bay Area and San Joaquin air basins.

3. The applicant proposed emission reduction credits are not adequate to mitigate the project's potential significant impacts to the state and the federal ozone, PM10 and PM2.5 air quality standards in the San Joaquin air basin.
4. The project's potential impacts to the area would be mitigated to a level of less than significant with the implementation of mitigation measures to secure emissions reductions locally equivalent to 175 tons per year of NOx and/or VOC, as ozone precursors, and 50 ton per year of PM10. Staff prefers that the reductions come from the SJVAPCD Heavy-Duty Engine Incentive and the proposed Wood Stove Replacement mitigation measures. Alternatively, a mixture of ERCs and engine and stove replacements equal, locally, to 175 tons per year of NOx and/or VOC, as ozone precursors, and 50 ton per year of PM10, would mitigate the project's potential impacts.

RECOMMENDATIONS

Staff recommends the following mitigation measures:

An agreement to limit the ammonia slip from the SCR system to no more than 5 ppm to lessen the potential impacts of the project on the area PM_{10} and $PM_{2.5}$ ambient air quality standards in both the Bay Area and San Joaquin air basins. Staff recommends the inclusion of this limit in Condition **AQ-25**.

An agreement to operate the fire pump diesel engine with ultra low sulfur diesel fuel to lessen the potential impacts of the project on the area PM_{10} and $PM_{2.5}$ ambient air quality standard in both the Bay Area and San Joaquin air basins. Staff recommends the inclusion of this restriction in Condition **AQ-68**.

The District has provided a Final Determination of Compliance, of which staff has incorporated the conclusion and appropriate conditions into the FSA. The District recommended conditions are presented here as Conditions 1 through 75. Staff also recommends the inclusion of Conditions of Certification **AQ-SC1** through **AQ-SC4** to address the construction-related impacts in both the Bay Area and San Joaquin air basins.

To secure emissions reductions locally equivalent to 175 tons per year of NO_x and/or VOC, as ozone precursors, and 50 ton per year of PM10. the reductions shall come from the following:

An agreement to provide enough funding to the SJVAPCD to subsidize the District's existing "Heavy-Duty Engine Incentive Program" to provide a reduction of 175 tons of ozone precursors (NO_x and/or VOC) for each year of the project lifetime. Staff recommends the inclusion of Condition of Certification **AQ-SC5** to address this mitigation measure; **AND**.

An agreement to design and implement a program to rebate $1,250 to each participant who volunteers to replace his or her existing wood stove with a new EPA certified unit. Staff recommends the inclusion of Condition of Certification **AQ-SC6** to address this mitigation measure; **OR**

Alternatively, the applicant could provide the necessary emissions reductions in the form of ERCs.

STAFF PROPOSED CONDITIONS OF CERTIFICATION

AQ-SC1 The project owner shall submit the resume(s) of each individual proposed to fill the designated Air Quality Construction Mitigation Manager (AQAQCMM) position to the CEC Compliance Project Manager (CPM) for approval. One or more individuals may hold this position. The owner shall be responsible for funding the costs of the AQCMM, however the AQCMM shall be allowed to report directly to the CPM. The AQCMM shall preferably have a minimum of eight years experience as follows, however the CPM shall consider all resumes submitted regardless of experience:

five years construction experience as a subcontractor or general contractor.

An engineering degree or an additional five years construction experience.

one year construction project management experience.

two years air quality assessment experience.

The AQCMM shall be responsible for implementing all mitigation measures related to construction equipment combustion emissions, construction monitoring and enforcing the effectiveness of construction mitigation measures as outlined in Conditions of Certification **AQ-SC3** and **AQ-SC4**. The AQCMM shall be onsite during all construction activities, until no longer deemed necessary by the CPM. The AQCMM shall be granted access to all areas of the main and linear facility construction sites. The AQCMM shall have the authority to stop specific construction activities on either the main or the linear facility construction sites as specified in Condition **AQ-SC3** (3) below. The AQCMM may not be terminated prior to the cessation of construction activities unless approval is granted by the CPM.

Verification The project owner shall submit the AQCMM resume(s) to the CPM for approval at least 60 days prior to site mobilization.

AQ-SC2 The project owner shall ensure that the AQCMM submits directly to the CPM for approval (and a copy to the project owner) a report of all compliance actions taken germane to Conditions of Certification **AQ-SC3** and **AQ-SC4**. The report shall include, at a minimum, the following elements:

Fugitive Dust Mitigation Monthly Report
(see Condition of Certification AQ-SC3)

a) A summary of each of the operation(s) planned for the following two months which may result in the generation of fugitive dust. Each description shall include a schedule, on-site location details and a list of proposed fugitive dust mitigation measures.

b) A summary of all mitigation activities implemented for each fugitive dust generating operation identified in a previous report. This report should provide a summary description of the operation, the mitigation measures implemented and the estimated effectiveness of each mitigation measure.

c) Details of all operation(s) requiring fugitive dust mitigation that are not identified in the previous report or the FDMP. Details shall include (at a minimum) a description of the operation, the date, duration, mitigation measures implemented, and an explanation for not reporting the operation in a previous report (or in the FDMP).

d) Identification of any failures of mitigation measures and details of the actions taken to reduce the identified impacts and prevent future failures of those mitigation measures.

e) Identification of any observation by the AQCMM of dust plumes beyond the property boundary of the main construction site or beyond an acceptable distance from the linear construction site and what actions (if any) where taken to abate the plume.

f) A summary of all ambient air monitoring data collected.

Diesel Construction Equipment Mitigation Monthly Report (see Condition of Certification AQ-SC4)

a) Identification of any changes, as approved by the CPM, to the Diesel Construction Equipment Mitigation Plan from the initial report or the last monthly report including any new contractors and their diesel construction equipment.

b) A Copy of all receipts or other documentation indicating types and amounts of fuel purchased, from whom, where delivered and on what date for the main and related linear construction sites.

c) Identification and verification of all diesel engines required to meet EPA or CARB 1996 off-road diesel equipment emission standards.

d) The suitability of the use of a catalyzed diesel particulate filter for a specific piece of construction equipment is to be determined by a qualified mechanic or engineer who must submit a report through the AQCMM to the CPM for approval. The identification of any suitability report initiated or pursued, or the completed report, should be included in the monthly report (in the month that it was completed) as should the verification of any subsequent installation of a catalyzed diesel particulate filter.

e) Identification of any observation by the AQCMM of exhaust plumes emanating from diesel-fired construction equipment beyond the property boundary of the main construction site or beyond an acceptable distance from the linear construction site and what actions (if any) where taken to abate the plume or future expected plumes.

Verification: The project owner shall ensure that the AQCMM submits directly to the CPM for approval (and a copy to the project owner), in the MCR, all compliance actions taken germane to Conditions of Certification **AQ-SC3** and **AQ-SC4**. The report is due within ten working days after the end of each reporting month.

AQ-SC3 The project owner shall ensure that the AQCMM prepares and submits to the CPM for approval, a Fugitive Dust Mitigation Plan (FDMP) that specifically identifies all fugitive dust mitigation measures that will be employed during the construction of the facility and related linears. The FDMP shall be administered on site by the full-time AQCMM.

The FDMP shall include a schedule of each operation planned for the first two months of the project that may result in the generation of fugitive dust, including location, source(s) of fugitive dust, and proposed mitigation measures specific to each operation/source.

The construction mitigation measures that shall be addressed in the FDMP include, but are not limited to, the following:

Identification of the employee parking area(s) and surface composition of those parking area(s)

The frequency of watering of unpaved roads and all disturbed areas

Application of chemical dust suppressants

Gravel in high traffic areas

Paved access aprons

Sandbags to prevent run off

Posted speed limit signs

Wheel washing areas prior to large trucks leaving the project site

Methods that will be used to clean tracked-out mud and dirt from the project site onto public roads

For any transportation of solid bulk material

1. Vehicle covers
2. Wetting of the transported material
3. Appropriate freeboard

Methods for the stabilization of storage piles and disturbed areas

Windbreaks at appropriate locations

Additional mitigation measures to be implemented at the direction of the AQCMM in the event that the standard measures fail to completely control dust from any activity and/or source

The suspension of all earth moving activities under windy conditions

On-site monitoring devices

In monitoring the effectiveness of all mitigation measures included in the FDMP, the AQCMM shall take into account the following, at a minimum:

a) Onsite spot checks of soil moisture content at locations where soil disturbance, movement and/or storage is occurring; and

b) Visual observations of all construction activities.

The AQCMM shall implement the following procedures for additional mitigation measures if the AQCMM determines that the existing mitigation measures are not resulting in effective mitigation:

1) The AQCMM shall direct more aggressive application of the existing mitigation methods if standard mitigation measures are not effective.

2) The AQCMM shall direct implementation of additional methods of mitigation if step #1 specified above fails to result in adequate mitigation.

3) The AQCMM shall direct a temporary shutdown of the source of the emissions if step #2 specified above fails to result in adequate mitigation within one) hour of the original determination. The activity shall not restart until circumstances leading to the problem have been addressed.

Verification: At least 30 days prior to site mobilization, the project owner shall provide the CPM with a copy of the FDMP for approval. Site mobilization shall not commence until the project owner receives approval of the FDMP from the CPM.

AQ-SC4 The project owner shall ensure that the AQCMM prepares and submits to the CPM for approval, a Diesel Construction Equipment Mitigation Plan (DCEMP) that will specifically identify diesel engine mitigation measures that will be employed during the construction phase of the main and related linear construction sites. The project owner shall ensure that the AQCMM will be responsible for directing implementation of and compliance with all measures identified in the DCEMP. The DCEMP shall address, at a minimum, the following mitigation measures:

Catalyzed diesel particulate filters (CDPF)

CARB certified ultra low sulfur diesel fuel, containing 15ppm sulfur or less (ULSD)

Diesel engines certified to meet EPA and/or CARB 1996 or better off-road equipment emission standards

Restricting diesel engine idle time, to the extent practical, to no more than ten minutes

The DCEMP shall include the following:

1. A list of all diesel-fueled, off-road, stationary or portable construction-related equipment to be used either on the main or the related linear construction sites. This list will initially be estimated and then subsequently be updated as specific contractors become identified. Prior to a contractor gaining access to the main or related linear construction sites, the project owner shall ensure that the AQCMM submits to the CPM for approval, an update of this list including all of the new contractor's diesel construction equipment.

2. Each piece of construction equipment listed under item #1 of this condition must demonstrate compliance according to the following mitigation requirements, except as noted in items #3, #4 and #5 of this condition:

Engine Size (BHP)	1996 CARB or EPA Certified Engine	Required Mitigation
< 100	NA	ULSD
> or = 100	Yes	ULSD
> or = 100	No	ULSD and CDPF, if suitable as determined by the AQCMM

3. If the construction equipment is intended to be on-site for ten days or less, then none of the mitigation measures identified in item #2 of this condition are required.

4. The CPM may grant relief from the mitigation measures listed in item #2 of this condition for a specific piece of equipment if the AQCMM can demonstrate that they have made a good faith effort to comply with the mitigation measures and that compliance is not possible.

5. Any implemented mitigation measure in item #2 of this condition may be terminated immediately if one of the following conditions exists, however the CPM must be informed within ten working days of the termination:

    5.1 The measure is excessively reducing normal availability of the construction equipment due to increased downtime for maintenance, and/or reduced power output due to an excessive increase in back pressure.

    5.2 The measure is causing or is reasonably expected to cause significant engine damage.

    5.3 The measure is causing or is reasonably expected to cause a significant risk to workers or the public.

    5.4 Any other seriously detrimental cause which has approval by the CPM prior to the termination being implemented.

6. All contractors must agree to limit diesel engine idle time on all diesel-powered equipment to no more than ten minutes, to the extent practical.

Verification: The project owner shall ensure that the AQCMM submits a DCEMP to the CPM for approval at least 30 days prior to site mobilization. The AQCMM will update the initial DCEMP (if necessary), no less than ten days prior to a specific contractor gaining access to either the main or related linear construction sites. The project owner shall ensure that the AQCMM notifies the CPM of any emergency termination within ten working days of the termination.

AQ-SC5 The project owner shall provide emissions reductions locally equivalent to 175 tons per year of NO_x and/or VOC, as ozone precursors.

Protocol: The project owner shall provide funds to the San Joaquin Valley Air Pollution Control District (SJVAPCD) to support its "Heavy-Duty Engine Incentive

Program." The funds shall be distributed to the SJVAPCD in four phases according to the following schedule:

(a) The first payment shall begin immediately after the project receives an Authority to Construct from the Bay Area Air Quality Management District. The fund shall be in sufficient quantity, plus five percent for administration costs, to finance new purchases, engine re-power, or retrofit qualified engines to generate 1,725 tons (based on 7.7 years lifetime) of NO_x and/or VOC emission reduction credits combined.

(b) The second payment shall begin in 2011. The fund shall be in sufficient quantity, plus five percent for administration costs, to finance new purchases, engine re-power, or retrofit qualified engines to generate 1,725 tons (based on 7.7 years lifetime) of NO_x and/or VOC emission reduction credits combined.

(c) The third payment shall begin in 2019. The fund shall be in sufficient quantity, plus five percent for administration costs, to finance new purchases, engine re-power, or retrofit qualified engines to generate 1,725 tons (based on 7.7 years lifetime) of NO_x and/or VOC emission reduction credits combined.

(d) The fourth payment shall begin in 2027. The fund shall be in sufficient quantity, plus five percent for administration costs, to finance new purchases, engine re-power, or retrofit qualified engines to generate 1,725 tons (based on 7.7 years lifetime) of NO_x and/or VOC emission reduction credits combined.

Funding for Phase 2, 3, or 4 to the SJVAPCD "Heavy-Duty Engine Incentive Program" shall be terminated if the program fails to achieve the necessary Phase I NO_x and/or VOC emission reduction credits specified above. In such case, or if the applicant chooses to purchase and provide emission reduction credits, or initiate other programs approved by the Commission staff to benefit the Air Quality in the Tracy/Livermore area, the reductions must be equivalent to 175 tpy of NO_x and/or VOC, combined,

"Qualified engine" means any internal combustion engine that meets the requirement specified in the current SJVAPCD "Heavy-Duty Engine Incentive Program", and has an operating base in the San Joaquin County or East of Interstate Highway 680 in Alameda County.

Verification: The project owner, in the annual report, shall provide the CPM information detailing the tons of emission reductions of NO_x and VOC secured from EAEC funding of the SJVAPCD "Heavy-Duty Engine Incentive Program," the purchase of emission reduction credits, or from other programs approved by the Commission staff to benefit the Air Quality in the Tracy/Livermore area. The reports shall contain, but not be limited to the number and types of qualified participating engines, the amount of NO_x and/or VOC emission reduction credits for each engine, the running total emission reduction credits secured and surrendered, and the operational location of these engines, the location of emission reductions, and/or the status emission reduction programs. The emissions reductions must be equivalent to 175 tpy of NO_x and/or VOC, combined.

AQ-SC6 The project owner shall provide emissions reductions locally equivalent to 50 tons per year of PM10.

Protocol: The project owner shall submit a plan for a fireplace retrofit/woodstove replacement program to the CPM for approval. The plan shall provide the following elements:

a) Provisions for a replacement fund to be made available on a first-come, first-serve basis to finance a five-year voluntary woodstove replacement/fireplace retrofit program which shall provide a minimum PM_{10} emission reductions of 7 tons/PM10 season. The replacement fund shall pay for the retrofit/ replacement costs of at least 395 current non-EPA certified fireplaces and woodstoves (up to a maximum of $1,250 for each retrofit/replacement) with an EPA-certified solid fuel heating device. The fund shall be capable of being drawn upon in any year of the five year program and as allowed by conditions of certification until the fund is depleted.

b) A procedure whereby the CPM would establish a list of approved retailers and professional, licensed installers. Each resident participating in the retrofit/replacement program would only do business with listed retailers or installers. Payments shall only be made to vendors or contractors who agree to participate in the program and who submit certification that the retrofit/replacement is permanent (by permanent removal of the wood stove doors and proper recycling of the old stove) and conforms to program requirements.

c) Submission to the CPM of quarterly status reports on the program, the status of reimbursements, and remaining funds available. In addition, the fund shall be audited annually.

d) A description of eligibility requirements, including that, for the first three years of the program, homes and businesses located within a fifteen-mile radius of the proposed facility will be eligible to participate in the program. Homes and businesses within a twenty five-mile radius of the EAEC facility would be eligible to participate in the fourth and fifth years if there are remaining funds.

If the program fails to achieve the necessary PM10 emission reduction specified above and the applicant chooses to purchase and provide emission reduction credits or initiate other programs approved by the CPM to benefit the Air Quality in the Tracy/Livermore area, the emission reductions provided by the project owner must be equivalent to 50 tpy of PM10.

Verification: No later than 30 days prior to commencement of construction, the project owner shall provide the CPM, for approval, a copy of the wood stove replacement program or a PM10 emission reduction program(s) designed to secure 50 tpy of PM10. The project owner shall surrender PM10 emission reductions and/or ERCs to the CPM within 60 days of securing the emission reduction or ERC. The project owner shall submit to the CPM a copy of the quarterly report within 45 days of the end of each quarter detailing the PM10 emission reductions, the method used to secure, and the emission reductions and/or ERCs surrendered to the CPM. The 4th quarter report shall contain an annual summary.

AQ-SC7 The project owner shall submit to the CPM for review and approval any modification proposed by either the project owner or issuing agency to any project air permit.

Verification: The project owner shall submit any proposed air permit modification to the CPM within five working days of its submittal either by 1) the project owner to an agency, or 2) receipt of proposed modifications from an agency. The project owner shall submit all modified air permits to the CPM within 15 days of receipt.

DISTRICT'S CONDITIONS OF CERTIFICATION

(A) Definitions:

Clock Hour:	Any continuous 60-minute period beginning on the hour
Calendar Day:	Any continuous 24-hour period beginning at 12:00 AM or 0000 hours
Year:	Any consecutive twelve-month period of time
Heat Input:	All heat inputs refer to the heat input at the higher heating value (HHV) of the fuel, in BTU/scf
Rolling 3-hour period:	Any consecutive three-hour period, not including start-up or shutdown periods
Firing Hours:	Period of time during which fuel is flowing to a unit, measured in minutes
MM BTU:	million british thermal units
Gas Turbine Start-up Mode:	The lesser of the first 180 minutes of continuous fuel flow to the Gas Turbine after fuel flow is initiated or the period of time from Gas Turbine fuel flow initiation until the Gas Turbine achieves two consecutive CEM data points in compliance with the emission concentration limits of conditions 25(b) and 25(d)
Gas Turbine Shutdown Mode:	The lesser of the 30 minute period immediately prior to the termination of fuel flow to the Gas Turbine or the period of time from non-compliance with any requirement listed in Conditions 25(b) through 25(d) until termination of fuel flow to the Gas Turbine
Specified PAHs:	The polycyclic aromatic hydrocarbons listed below shall be considered to be Specified PAHs for these permit conditions. Any emission limits for Specified PAHs refer to the sum of the emissions for all six of the following compounds Benzo[a]anthracene Benzo[b]fluoranthene Benzo[k]fluoranthene Benzo[a]pyrene

	Dibenzo[a,h]anthracene
	Indeno[1,2,3-cd]pyrene
Corrected Concentration:	The concentration of any pollutant (generally NO_x, CO, or NH_3) corrected to a standard stack gas oxygen concentration. For emission points P-1 (combined exhaust of S-1 Gas Turbine and S-2 HRSG duct burner) P-2 (combined exhaust of S-3 Gas Turbine and S-4 HRSG duct burner), and P-3 (combined exhaust of S-5 Gas Turbine and S-6 HRSG duct burner), the standard stack gas oxygen concentration is 15% O_2 by volume on a dry basis. For emission point P-4 (auxiliary boiler), the standard stack gas oxygen concentration is 3% O_2 by volume on a dry basis
Commissioning Activities:	All testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the EAEC construction contractor to insure safe and reliable steady state operation of the gas turbines, heat recovery steam generators, steam turbine, and associated electrical delivery systems
Commissioning Period:	The Period shall commence when all mechanical, electrical, and control systems are installed and individual system start-up has been completed, or when a gas turbine is first fired, whichever occurs first. The period shall terminate when the plant has successfully completed both performance and compliance testing. The commissioning period shall not exceed 180 days under any circumstances.
Precursor Organic Compounds (POCs):	Any compound of carbon, excluding methane, ethane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate
CEC CPM:	California Energy Commission Compliance Program Manager
EAEC:	East Altamont Energy Center

(B) Applicability:

Conditions 1 through 16 and their verifications shall only apply during the commissioning period as defined above. Unless otherwise indicated, Conditions 17 through 74 shall apply after the commissioning period has ended.

Conditions for the Commissioning Period

AQ-1 The project owner of the East Altamont Energy Center (EAEC) shall minimize emissions of carbon monoxide and nitrogen oxides from S-1, S-3, and S-5 Gas Turbines and S-2, S-4, and S-6 Heat Recovery Steam Generators (HRSGs) to the maximum extent possible during the commissioning period.

Verification: The project owner shall submit in the monthly compliance report to the CPM how this condition is being complied with.

AQ-2 At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, the project owner shall **tune** the S-1, S-3, & S-5 Gas Turbine combustors and S-2, S-4, & S-6 Heat Recovery Steam Generator duct burners to minimize the emissions of carbon monoxide and nitrogen oxides.

Verification: The project owner shall submit in the monthly compliance report to the CPM how this condition is being complied with.

AQ-3 At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, the project owner shall install, **adjust**, and operate the A-1, A-3, A-5, & A-7 Oxidation Catalysts and A-2, A-4, A-6, & A-8 SCR Systems to minimize the emissions of carbon monoxide and nitrogen oxides from S-1, S-3, & S-5 Gas Turbines, S-2, S-4, & S-6 Heat Recovery Steam Generators, and S-7 Auxiliary Boiler.

Verification: The project owner shall submit in the monthly compliance report to the CPM how this condition is being complied with.

AQ-4 Coincident with the steady-state operation of A-2, A-4, & A-6 SCR Systems and A-1, A-3, A-5, & A-7 Oxidation Catalysts pursuant to conditions 3, 9, 10, and 11, the **project owner** shall operate the Gas Turbines (S-1, S-3, & S-5) and the HRSGs (S-2, S-4, & S-6) in such a manner as to comply with the NO_x and CO emission limitations specified in conditions 25(a) through 25(d).

Verification: The project owner shall submit in the monthly compliance report to the CPM how this condition is being complied with.

AQ-5 Coincident with the steady-state operation of the A-8 SCR Systems and A-7 Oxidation **Catalyst pursuant** to conditions 3 and 12, the project owner shall operate the S-7 Auxiliary Boiler in such a manner as to comply with the NO_x and CO emission limitations specified in conditions 33(a) through 33(d).

Verification: The project owner shall submit in the monthly compliance report to the CPM how this condition is being complied with.

AQ-6 The project owner of the EAEC shall submit a plan to the District Permit Services Division and the CEC CPM at least four weeks prior to first firing of S-1, S-3, or S-5 Gas Turbines describing the procedures to be followed during the commissioning of the turbines, HRSGs, auxiliary boiler, and steam turbine. The plan shall include a **description** of each commissioning activity, the anticipated duration of **each** activity in hours, and the purpose of the activity. The activities described shall include, but not be limited to, the tuning of the Dry-Low-NO_x combustors, the installation and operation of the required emission control systems, the installation, calibration, and testing of the CO and NO_x continuous emission monitors, and any activities requiring the firing of the Gas Turbines (S-1, S-3, & S-5), HRSGs (S-2, S-4, & S-6), and S-7 Auxiliary Boiler without abatement by their respective Oxidation Catalysts and/or SCR Systems. The project owner shall not fire any of the Gas Turbines (S-1, S-3, or S-5) sooner than 28 days after the District receives the commissioning plan.

Verification: The project owner shall submit in the monthly compliance report to the CPM how this condition is being complied with.

AQ-7 During the commissioning period, the project owner of the EAEC shall demonstrate **compliance** with conditions 13, 14, and 15 through the use of **properly** operated and maintained continuous emission monitors and data recorders for the following parameters:

firing hours

fuel flow rates

stack gas nitrogen oxide emission concentrations,

stack gas carbon monoxide emission concentrations

stack gas oxygen concentrations.

The monitored parameters shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation) for the Gas Turbines (S-1, S-3, & S-5), HRSGs (S-2, S-4, & S-6), and S-7 Auxiliary Boiler. The project owner shall use District-approved methods to calculate heat input rates, nitrogen dioxide mass emission rates, carbon monoxide mass emission rates, and NO_x and CO emission concentrations, summarized for each clock hour and each calendar day. The project owner shall retain records on site for at least 5 years from the date of entry and make such records available to District personnel upon request.

Verification: The project owner shall submit in the monthly compliance report to the CPM how this condition is being complied with.

AQ-8 The project owner shall install, calibrate, and operate the District-approved continuous monitors specified in condition 7 prior to first firing of the Gas Turbines (S-1, S-3, & S-5), Heat Recovery Steam Generators (S-2, S-4, & S-6), and S-7 Auxiliary Boiler. **After** first firing of the turbines and/or auxiliary boiler, the project owner shall adjust the detection range of these continuous emission monitors as necessary to accurately measure the resulting range of CO and NO_x emission concentrations. The type, specifications, and location of these monitors shall be subject to District review and approval.

Verification: The project owner shall submit in the monthly compliance report to the CPM how this condition is being complied with.. In addition, the project owner shall provide evidence of the District's approval of the emission monitoring system to the CPM prior to first firing of the gas turbines.

AQ-9 The project owner shall not fire the S-1 Gas Turbine and S-2 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-1 SCR System and/or abatement of carbon monoxide emissions by A-1 Oxidation Catalyst for more than 300 hours during the commissioning period. Such operation of S-1 Gas Turbine and S-2 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and/or oxidation catalyst in place. Upon completion of these activities, the project owner shall provide written notice to the District Permit

Services and Enforcement Divisions, and the CPM, and the unused balance of the 300 firing hours without abatement shall expire.

Verification: The project owner shall submit in the monthly compliance report to the CPM how this condition is being complied with.

AQ-10 The project owner shall not fire the S-3 Gas Turbine and S-4 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-3 SCR System and/or abatement of carbon monoxide emissions by A-3 Oxidation Catalyst for more than 300 hours during the commissioning period. Such operation of S-3 Gas Turbine and S-4 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and/or oxidation catalyst in place. Upon completion of these activities, the project owner shall provide written notice to the District Permit Services and Enforcement Divisions, and the CPM, and the unused balance of the 300 firing hours without abatement shall expire.

Verification: The project owner shall submit in the monthly compliance report to the CPM how this condition is being complied with.

AQ-11 The project owner shall not fire the S-5 Gas Turbine and S-6 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-5 SCR System and/or abatement of carbon monoxide emissions by A-5 Oxidation Catalyst for more than 300 hours during the commissioning period. Such operation of S-5 Gas Turbine and S-6 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and/or oxidation catalyst in place. Upon completion of these activities, the project owner shall provide written notice to the District Permit Services and Enforcement Divisions, and the CPM, and the unused balance of the 300 firing hours without abatement shall expire.

Verification: The project owner shall submit in the monthly compliance report to the CPM how this condition is being complied with.

AQ-12 The project owner shall not fire the S-7 Auxiliary Boiler without abatement of carbon monoxide emissions by A-7 Oxidation Catalyst and/or abatement of nitrogen oxide emissions by A-8 SCR System for more than 100 hours during the commissioning period. Such operation of S-7 Auxiliary Boiler without abatement by A-7 and/or A-8 shall be limited to discrete commissioning activities that can only be properly executed **without** the SCR system and/or oxidation catalyst in place. Upon completion of these activities, the project owner shall provide written notice to the District Permit Services and Enforcement Divisions, and the CPM, and the unused balance of the 100 firing hours without abatement shall expire.

Verification: The project owner shall submit in the monthly compliance report to the CPM how this condition is being complied with.

AQ-13 The total mass emissions of nitrogen oxides, carbon monoxide, precursor organic compounds, PM_{10}, and sulfur dioxide that are emitted by the Gas Turbines (S-1, S-3, & S-5), **Heat** Recovery Steam Generators (S-2, S-4, & S-6), S-7 Auxiliary Boiler, S-9 Fire Pump Diesel Engine, and S-10 Emergency

Generator during the commissioning period shall accrue towards the consecutive twelve-month emission limitations specified in condition 35.

Verification: The project owner shall submit in the monthly compliance report to the CPM how this condition is being complied with.

AQ-14 The project owner shall not operate the Gas Turbines (S-1, S-3, & S-5) and Heat Recovery Steam Generators (S-2, S-4, & S-6) in a manner such that the combined pollutant **emissions** from these sources will exceed the following limits during the commissioning period. These emission limits shall include emissions resulting from the start-up and shutdown of the Gas Turbines (S-1, S-3, & S-5).

NO_x (as NO_2)	4,805 pounds per calendar day	381 pounds per hour
CO	11,498 pounds per calendar day	930 pounds per hour
POC (as CH_4)	495 pounds per calendar day	
PM_{10}	660 pounds per calendar day	
SO_2	42 pounds per calendar day	

Verification: The project owner shall submit in the monthly compliance report to the CPM how this condition is being complied with.

AQ-15 The project owner shall not operate the S-7 Auxiliary Boiler such that the pollutant emissions will exceed the following limits during the commissioning period. These emission limits shall include emissions that occur during Auxiliary Boiler start-ups.

NO_x (as NO_2)	428 pounds per calendar day	33 pounds per hour
CO	368 pounds per calendar day	22 pounds per hour
POC (as CH_4)	25.4 pounds per calendar day	
PM_{10}	96 pounds per calendar day	
SO_2	12.4 pounds per calendar day	

Verification: The project owner shall submit in the monthly compliance report to the CPM how this condition is being complied with..

AQ-16 Prior to the end of the Commissioning Period, the project owner shall conduct a District and CEC approved source test using external continuous emission monitors to determine compliance with the limitations specified in condition 26. The source test shall determine NO_x, CO, and POC emissions during start-up and shutdown of the gas turbines. The POC emissions shall be analyzed for methane and ethane to **account** for the presence of unburned natural gas. The source test shall include a minimum of three start-up and three shutdown periods. Twenty working days before the execution of the source tests, the project owner shall submit to the District and the CPM a detailed source test plan designed to satisfy the requirements of this condition. The District and the CEC CPM will notify the project owner of any necessary modifications to the plan within 20 working days of receipt of the plan; otherwise, the plan shall be deemed approved. The project owner shall incorporate the District and CPM comments into the test plan. The project owner shall notify the District and the CEC CPM within seven (7) working days prior to the planned source testing date. Source test results shall be submitted to the District and the CEC CPM within 60 days of the source testing date.

Verification: No later than 35 working days before the commencement of the source tests, the project owner shall submit to the District and the CPM a detailed source test plan designed to satisfy the requirements of this condition. The District and the CPM will notify the project owner of any necessary modifications to the plan within 20 working days of receipt of the plan; otherwise, the plan shall be deemed approved. The project owner shall incorporate the District and CPM comments into the test plan. The project owner shall notify the District and the CPM within seven (7) working days prior to the planned source testing date. Source test results shall be submitted to the District and the CPM within 90 days of the source testing date.

Conditions for the Gas Turbines (S-1, S-3, & S-5) and the Heat Recovery Steam Generators (HRSGs; S-2, S-4, & S-6) for the Period Following Commissioning

AQ-17 The project owner shall fire the Gas Turbines (S-1, S-3, and S-5) and HRSG Duct Burners (S-2, S-4, and S-6) exclusively with natural gas. (BACT for SO_2 and PM_{10})

Verification: The project owner shall complete, on a daily basis, a laboratory analysis showing the sulfur content of natural gas being burned at the facility. The daily sulfur analysis reports shall be incorporated into the quarterly compliance reports.

AQ-18 The project owner shall not operate the units such that the combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-1 & S-2, S-3 & S-4, and S-5 & S-6) exceeds 2,630.8 MM BTU (HHV) per hour, averaged over any rolling 3-hour period. (PSD for NO_x)

Verification: As part of the quarterly and annual compliance reports, the project owner shall include information on the date, time, and duration of any violation of this permit condition.

AQ-19 The project owner shall not operate the units such that the combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-1 & S-2, S-3 & S-4, and S-5 & S-6) exceeds 63,139.2 MM BTU (HHV) per calendar day. (PSD for PM_{10})

Verification: As part of the quarterly and annual compliance reports, the project owner shall include information on the date, time, and duration of any violation of this permit condition.

AQ-20 The project owner shall not operate the units such that the combined cumulative heat input rate for the Gas Turbines (S-1, S-3, & S-5) and the HRSGs (S-2, S-4, & S-6) exceeds 61,100,064 MM BTU (HHV) per year. (Offsets)

Verification: As part of the quarterly and annual compliance reports, the project owner shall include information on the date, time, and duration of any violation of this permit condition.

AQ-21 The project owner shall not fire the HRSG duct burners (S-2, S-4, and S-6) unless its associated Gas Turbine (S-1, S-3, and S-5, respectively) is in operation. (BACT for NO_x)

Verification: As part of the quarterly and annual compliance reports, the project owner shall include information on the date, time, and duration of any violation of this permit condition.

AQ-22 The project owner shall ensure that the S-1 Gas Turbine and S-2 HRSG are abated by the properly operated and properly maintained A-2 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-2 SCR catalyst bed has reached minimum operating temperature. (BACT for NO_x)

Verification: As part of the quarterly and annual compliance reports, the project owner shall provide information on any major problem in the operation of the Oxidizing Catalyst and Selective Catalytic Reduction Systems for the Gas Turbines and HRSGs. The information shall include, at a minimum, the date and description of the problem and the steps taken to resolve the problem.

AQ-23 The project owner shall ensure that the S-3 Gas Turbine and S-4 HRSG are abated by the properly operated and properly maintained A-4 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-4 SCR catalyst bed has reached minimum operating temperature. (BACT for NO_x)

Verification: As part of the quarterly and annual compliance reports, the project owner shall provide information on any major problem in the operation of the Oxidizing Catalyst and Selective Catalytic Reduction Systems for the Gas Turbines and HRSGs. The information shall include, at a minimum, the date and description of the problem and the steps taken to resolve the problem.

AQ-24 The project owner shall ensure that the S-5 Gas Turbine and S-6 HRSG are abated by the properly operated and properly maintained A-6 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-6 SCR catalyst bed has reached minimum operating temperature. (BACT for NO_x)

Verification: As part of the quarterly and annual compliance reports, the project owner shall provide information on any major problem in the operation of the Oxidizing Catalyst and Selective Catalytic Reduction Systems for the Gas Turbines and HRSGs. The information shall include, at a minimum, the date and description of the problem and the steps taken to resolve the problem.

AQ-25 The project owner shall ensure that the Gas Turbines (S-1, S-3, & S-5) and HRSGs (S-2, S-4, & S-6) comply with requirements (a) through (h) under all operating scenarios, including duct burner firing mode and steam injection power augmentation mode. Requirements (a) through (h) do not apply during a gas turbine start-up or shutdown. (BACT, PSD, and Toxic Risk Management Policy)

(a) Nitrogen oxide mass emissions (calculated as NO_2) at P-1 (the combined exhaust point for S-1 Gas Turbine and S-2 HRSG after abatement by A-2

SCR System) shall not ex
MM BTU (HHV) of natural gas fired. Nitrogen oxide mass emissions (calculated as NO_2) at P-2 (the combined exhaust point for S-3 Gas Turbine and S-4 HRSG after abatement by A-4 SCR System) shall not exceed 19 pounds per hour or 0.00723 lb/MM BTU (HHV) of natural gas fired.

Nitrogen oxide mass emissions (calculated as NO_2) at P-3 (the combined exhaust point for S-5 Gas Turbine and S-6 HRSG after abatement by A-6 SCR System) shall not exceed 19 pounds per hour or 0.00723 lb
(HHV) of natural gas fired.

(PSD for NO_x)

(b) The nitrogen oxide emission concentration at emission points P-1, P-2, and P-3 each shall not exceed 2.0 ppmv, on a dry basis, corrected to 15% O_2, averaged over any 1-hour period. (BACT for NO_x)

(c) Carbon monoxide mass emissions at P-1, P-2, and P-3 each shall not exceed 23.15 pounds per hour or 0.0088 lb/MM BTU of natural gas fired, averaged over any rolling 3-hour period. (PSD for CO)

(d) The carbon monoxide emission concentration at P-1, P-2, and P-3 each shall not exceed 4.0 ppmv, on a dry basis, corrected to 15% O_2, averaged over any rolling 3-hour period. (BACT for CO)

(e) Ammonia (NH_3) emission concentrations at P-1, P-2, and P-3 each shall not exceed 5 ppmv, on a dry basis, corrected to 15% O_2, averaged over any rolling 3-hour period. This ammonia emission concentration shall be verified by the continuous recording of the ammonia injection rate to A-2, A-4, and A-6 SCR Systems. The correlation between the gas turbine and HRSG heat input rates, A-2, A-4, and A-6 SCR System ammonia injection rates, and corresponding ammonia emission concentration at emission points P-1, P-2, and P-3 shall be determined in accordance with permit condition 40. (TRMP for NH_3)

(f) Precursor organic compound (POC) mass emissions (as CH_4) at P-1, P-2, and P-3 each shall not exceed 6.64 pounds per hour or 0.00252 lb/MM BTU of natural gas fired. (BACT)

(g) Sulfur dioxide (SO_2) mass emissions at P-1, P-2, and P-3 each shall not exceed 1.84 pounds per hour or 0.0007 lb/MM BTU of natural gas fired. (BACT)

(h) Particulate matter (PM_{10}) mass emissions at P-1, P-2, and P-3 each shall not exceed 9 pounds per hour when the HRSG duct burners are not in operation. Particulate matter (PM_{10}) mass emissions at P-1, P-2, and P-3 each shall not exceed 11.5 pounds per hour when HRSG duct burners are in operation. (BACT)

(i) Compliance with the hourly NOx emission limitations specified in condition 25(a) and 25(b) shall not be required during short-term excursions limited to a cumulative total of 10 hours per rolling 12-month period. Short-term excursions are defined as 15-minute periods designated by the project owner that are the direct result of transient load conditions, not to exceed

ceed 19 pounds per hour or 0.00723 lb/MM BTU four consecutive 15-minute periods, when the 15-minute average NOx concentration exceeds 2.0 ppmv, dry @ 15% O_2. Examples of transient load conditions include, but are not limited to the following:

(1) Initiation/shutdown of combustion turbine inlet air cooling

(2) Initiation/shutdown of combustion turbine steam injection for power augmentation

(3) Rapid combustion turbine load changes

(4) Initiation/shutdown of HRSG duct burners

The maximum 1-hour average NOx concentration for periods that include short-term excursions shall not exceed 30 ppmv, dry @ 15% O_2. All emissions during short-term excursions shall be included in all calculations of hourly, daily, and annual mass emission rates as required by this permit.

Verification: The project owner shall submit to the District and CPM, quarterly reports for the proceeding calendar quarter within 30 days from the end of the quarter. The report for the fourth quarter can be an annual compliance summary for the preceding year. The quarterly and annual compliance summary reports shall contain the following information.

(a) Operating parameters of emission control equipment, including but not limited to ammonia injection rate, NO_x emission rate and ammonia slip.

(b) Total plant operation time (hours), number of startups, hours in cold startup, hours in warm startup, hours in hot startup, and hours in shutdown.

(c) Date and time of the beginning and end of each startup and shutdown period.

(d) Average plant operation schedule (hours per day, days per week, weeks per year).

(e) All continuous emissions data reduced and reported in accordance with the District approved CEMS protocol.

(f) Maximum hourly, maximum daily, total quarterly, and total calendar year emissions of NO_x, CO, PM_{10}, VOC and SO_x (including calculation protocol).

(g) Fuel sulfur content (monthly laboratory analyses, monthly natural gas sulfur content reports from the natural gas supplier(s), or the results of a custom fuel monitoring schedule approved by the District.

(h) A log of all excess emissions, including the information regarding malfunctions/breakdowns.

(i) Any permanent changes made in the plant process or production, which would affect air pollutant emissions, and indicate when changes were made.

(j) Any maintenance to any air pollutant control system (recorded on an as-performed basis).

In addition, this information shall be maintained on site for a minimum of five (5) years and shall be provided to District personnel on request.

AQ-26 The project owner shall ensure that the regulated air pollutant mass emission rates from each of the Gas Turbines (S-1, S-3, and S-5) during a start-up or a shutdown does not exceed the limits established below. (PSD)

	Start-Up (lb/start-up)	Shutdown (lb/shutdown)
Oxides of Nitrogen (as NO_2)	240	80
Carbon Monoxide (CO)	2,514	902
Precursor Organic Compounds (as CH_4)	48	1 16

Verification: The project owner shall submit to the District and CPM the quarterly and annual compliance reports as required by Condition 25.

AQ-27 No more than one Gas Turbine (S-1, S-3, or S-5) shall be in start-up mode at any point in time. (PSD).

Verification: The project owner shall submit to the District and CPM the quarterly and annual compliance reports as required by Condition 25 and report any instance in which more than one turbine has been in start-up mode.

Conditions for S-7 Auxiliary Boiler

AQ-28 The project owner shall fire the Auxiliary Boiler exclusively with natural gas. (BACT for SO_2 and PM_{10})

Verification: The project owner shall maintain, on a daily basis, a laboratory analysis showing the sulfur content of natural gas being burned at the facility. The daily sulfur analysis reports shall be incorporated into the quarterly compliance reports.

AQ-29 The project owner shall not operate the unit such that the heat input rate to S-7 Auxiliary Boiler exceeds 129 million BTU per hour, averaged over any rolling 3-hour period. (Cumulative Increase)

Verification: As part of the quarterly and annual compliance reports, the project owner shall include information on the date, time, and duration of any violation of this permit condition.

AQ-30 The project owner shall not operate the unit such that the daily heat input rate to S-7 Auxiliary Boiler exceeds 3,096 million BTU per day. (Cumulative Increase)

Verification: As part of the quarterly and annual compliance reports, the project owner shall include information on the date, time, and duration of any violation of this permit condition.

AQ-31 The project owner shall not operate the unit such that the combined cumulative heat input rate to S-7 Auxiliary Boiler exceeds 387,000 million BTU per consecutive twelve month period. (Cumulative Increase)

Verification: As part of the quarterly and annual compliance reports, the project owner shall include information on the date, time, and duration of any violation of this permit condition.

AQ-32 The project owner shall ensure that S-7 Auxiliary Boiler exhaust gas is abated by A-7 Oxidation Catalyst and A-8 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at S-7 and the A-8 SCR catalyst bed has reached minimum operating temperature. (BACT)

Verification: As part of the quarterly and annual compliance reports, the project owner shall include information on any major problem in the operation of the Oxidation Catalyst and the SCR systems for the boiler. The information shall include, at a minimum, the date, time, duration, and description of the problem, and the steps taken to resolve the problem.

shall not exceed 0.0114 lb/MM BTU (HHV) of natural gas

AQ-33 The project owner shall ensure that S-7 Auxiliary Boiler complies with requirements (a) through (h) at all times, except during an auxiliary boiler start-up or shutdown. (BACT, PSD)

(a) Nitrogen oxide mass emissions (calculated as NO_2) at P-4 (the exhaust point for S-7 Auxiliary Boiler, after abatement by A-7 Oxidation Catalyst and A-8 SCR System)
fired or 1.5 pounds per hour, averaged over any rolling 3-hour period. (PSD for NO_x)

(b) The nitrogen oxide emission concentration at P-4 shall not exceed 9.0 ppmv, on a dry basis, corrected to 3% O_2, averaged over any rolling 3-hour period. (BACT for NO_x)

(c) Carbon monoxide mass emissions at P-4 (the exhaust point for S-7 Auxiliary Boiler, after abatement by A-7 Oxidation Catalyst) shall not exceed 0.0386 lb/MM BTU (HHV) of natural gas fired or 5.0 pounds per hour, averaged over any rolling 3-hour period. (PSD for CO)

(d) The carbon monoxide emission concentration at P-4 shall not exceed 50 ppmv, on a dry basis, corrected to 3% O_2, averaged over any rolling 3-hour period. (BACT for CO)

(e) The precursor organic compound (POC) mass emission rates at P-4 shall not exceed 0.6 pounds per hour. (BACT for POC)

(f) The ammonia (NH_3) emission concentrations at P-4 shall not exceed 10 ppmv, on a dry basis, corrected to 3% O_2, averaged over any rolling 3-hour period. This ammonia emission concentration shall be verified by the continuous recording of the ammonia injection rate to A-8 SCR System. The correlation between the auxiliary boiler heat input rates, A-8 SCR System ammonia injection rate, and corresponding ammonia emission concentration at emission points P-4 shall be determined in accordance with permit condition 55. (TRMP for NH_3)

(g) Sulfur dioxide (SO_2) mass emissions at P-4 shall not exceed 0.09 pounds per hour or 0.0007 lb/MM BTU of natural gas fired. (BACT)

(h) Particulate matter (PM_{10}) mass emissions at P-4 shall not exceed 2.65 pounds per hour or 0.0205 lb/MM BTU of natural gas fired. (BACT)

Verification: The project owner shall submit to the District and CPM the quarterly and annual compliance reports as required by Condition 25.

Conditions for All Sources

AQ-34 The project owner shall not allow total combined emissions from the Gas Turbines and HRSGs (S-1, S-2, S-3, S-4, S-5, and S-6), S-7 Auxiliary Boiler, S-9 Fire Pump Diesel Engine, and S-10 Emergency Generator, including emissions generated during Gas Turbine start-ups and shutdowns to exceed the following limits during any calendar day:

(a) 2,030.4 pounds of NO_x (as NO_2) per day (CEQA)

(b) 11,633.6 pounds of CO per day (PSD)

(c) 569.3 pounds of POC (as CH_4) per day (CEQA)

(d) 949.4 pounds of PM_{10} per day (PSD)

(e) 135.5 pounds of SO_2 per day (BACT)

Verification: The project owner shall submit to the District and CPM the quarterly and annual compliance reports as required by Condition 25.

AQ-35 The project owner shall not allow cumulative combined emissions from the Gas Turbines and HRSGs (S-1, S-2, S-3, S-4, S-5, and S-6), S-7 Auxiliary Boiler, S-8 Cooling Tower, S-9 Fire Pump Diesel Engine, and S-10 Emergency Generator, including emissions generated during gas turbine start-ups and shutdowns to exceed the following limits during any consecutive twelve-month period:

(a) 263 tons of NO_x (as NO_2) per year (Offsets)

(b) 793.6 tons of CO per year (Cumulative Increase, PSD)

(c) 73.7 tons of POC (as CH_4) per year (Offsets)

(d) 148 tons of PM_{10} per year (Offsets)

(e) 21.33 tons of SO_2 per year (Cumulative Increase)

Verification: The project owner shall submit to the District and CPM the quarterly and annual compliance reports as required by Condition 25.

AQ-36 The project owner shall not allow the combined heat input rate to the Gas Turbines and HRSGs (S-1, S-2, S-3, S-4, S-5, and S-6) and Auxiliary Boiler (S-7) to exceed 190,450 million BTU per calendar day. (PSD, CEC Offsets)

Verification: The project owner shall submit to the District and CPM the quarterly and annual compliance reports as required by Condition 25.

AQ-37 The project owner shall not allow the cumulative heat input rate to the Gas Turbines and HRSGs (S-1, S-2, S-3, S-4, S-5, and S-6) and Auxiliary Boiler (S-7) combined to exceed 61,487,064 million BTU per year. (Offsets)

Verification: The project owner shall submit to the District and CPM the quarterly and annual compliance reports as required by Condition 25.

AQ-38 The project owner shall not allow the maximum projected annual toxic air contaminant emissions (per condition 41) from the Gas Turbines and HRSGs (S-1, S-2, S-3, S-4, S-5, & S-6) combined to exceed the following limits:

formaldehyde	9,874.2 pounds per year
benzene	199.3 pounds of per year
Specified polycyclic aromatic hydrocarbons (PAHs)	9.9 pounds of per year

unless the following requirement is satisfied:

The project owner shall perform a health risk assessment to determine the total facility risk using the emission rates determined by source testing and the most current Bay Area Air Quality Management District approved procedures and unit risk factors in effect at the time of the analysis. This risk analysis shall be submitted to the District and the CEC CPM within 60 days of the source test date. The project owner may request that the District and the CEC CPM revise the carcinogenic compound emission limits specified above. If the project owner demonstrates to the satisfaction of the APCO that these revised emission limits will not result in a significant cancer risk, the District and the CEC CPM may, at their discretion, adjust the carcinogenic compound emission limits listed above. (TRMP)

Verification: Compliance with condition 41 shall be deemed as compliance with this condition. In addition, approval by the District and the CPM of the reports prepared for condition 41 will constitute a verification of compliance with this condition.

AQ-39 The project owner shall demonstrate compliance with conditions 18 through 21, 25(a) through 25(d), 26, 27, 29, 30, 31, 33(a) through 33(d), 34(a), 34(b), 35(a), and 35(b) by using properly operated and maintained continuous monitors (during all hours of operation including equipment Start-up and Shutdown periods) for all of the following parameters:

(a) Firing Hours and Fuel Flow Rates for each of the following sources: S-1 & S-2 combined, S-3 & S-4 combined, S-5 & S-6 combined, and S-7.

(b) Oxygen (O_2) Concentration, Nitrogen Oxides (NO_x) Concentration, and Carbon Monoxide (CO) Concentration at each of the following exhaust points: P-1, P-2, P-3, and P-4.

(c) Ammonia injection rate at A-2, A-4, A-6, and A-8 SCR Systems

The project owner shall record all of the above parameters every 15 minutes (excluding normal calibration periods) and shall summarize all of the above parameters for each clock hour. For each calendar day, the project owner shall calculate and record the total firing hours, the average hourly fuel flow rates, and pollutant emission concentrations.

The project owner shall use the parameters measured above and District-approved calculation methods to calculate the following parameters:

(d) Heat Input Rate for each of the following sources: S-1 & S-2 combined, S-3 & S-4 combined, S-5 & S-6 combined, and S-7.

(e) Corrected NO_x concentration, NO_x mass emission rate (as NO_2), corrected CO concentration, and CO mass emission rate at each of the following exhaust points: P-1, P-2, P-3, and P-4.

For each source, source grouping, or exhaust point, the project owner shall record the parameters specified in conditions 39(e) and 39(f) at least once every 15 minutes (excluding normal calibration periods). As specified below, the project owner shall calculate and record the following data:

a) total Heat Input Rate for every clock hour and the average hourly Heat Input Rate for every rolling 3-hour period.

b) on an hourly basis, the cumulative total Heat Input Rate for each calendar day for the following: each Gas Turbine and associated HRSG combined, the auxiliary boiler and all seven sources (S-1, S-2, S-3, S-4, S-5, S-6, & S-7) combined. hour period.

c) the average NO_x mass emission rate (as NO_2), CO mass emission rate, and corrected NO_x and CO emission concentrations for every clock hour and for every rolling 3-

d) on an hourly basis, the cumulative total NO_x mass emissions (as NO_2) and the cumulative total CO mass emissions, for each calendar day for the following: each Gas Turbine and associated HRSG combined, the auxiliary boiler, and all seven sources (S-1, S-2, S-3, S-4, S-5, S-6, & S-7) combined.

e) For each calendar day, the average hourly Heat Input Rates, Corrected NO_x emission concentration, NO_x mass emission rate (as NO_2), corrected CO emission concentration, and CO mass emission rate for each Gas Turbine and associated HRSG combined and the auxiliary boiler.

f) on a daily basis, the cumulative total NO_x mass emissions (as NO_2) and cumulative total CO mass emissions, for the previous consecutive twelve month period for all seven sources (S-1, S-2, S-3, S-4, S-5, S-6, & S-7) combined.

(1-520.1, 9-9-501, BACT, Offsets, NSPS, PSD, Cumulative Increase)

Verification: At least 30 days before first fire, the project owner shall submit to the CPM a plan on how the measurements and recordings required by this condition will be performed.

AQ-40 To demonstrate compliance with conditions 25(f), 25(g), 25(h), 26, 33(e), 33(g), 33(h), 34(c) through 34(e), and 35(c) through 35(e), the project owner shall calculate and record on a daily basis, the Precursor Organic Compound (POC) mass emissions, Fine Particulate Matter (PM_{10}) mass emissions (including condensable particulate matter), and Sulfur Dioxide (SO_2) mass emissions from each power train. The project owner shall use the actual Heat Input Rates calculated pursuant to condition 39, actual Gas Turbine Start-up Times, actual Gas Turbine Shutdown Times, and CEC and District-approved emission factors to calculate these emissions. The calculated emissions shall be presented as follows:

(a) For each calendar day, POC, PM_{10}, and SO_2 emissions shall be summarized for: each power train (Gas Turbine and its respective HRSG combined) and all seven sources (S-1, S-2, S-3, S-4, S-5, S-6, & S-7) combined.

(b) on a daily basis, the cumulative total POC, PM_{10}, and SO_2 mass emissions, for each year for all seven sources (S-1, S-2, S-3, S-4, S-5, S-6, & S-7) combined.

(Offsets, PSD, Cumulative Increase)

Verification: The project owner shall submit to the District and CPM the quarterly and annual compliance reports as required by Condition 25.

AQ-41 To demonstrate compliance with Condition 38, the project owner shall calculate and record on an annual basis the maximum projected annual emissions of: Formaldehyde, Benzene, and Specified PAH's. Maximum projected annual emissions shall be calculated using the maximum Heat Input Rate of 61,100,064 MM BTU/year and the highest emission factor (pounds of pollutant per MM BTU of heat input) determined by any source test of the S-1, S-3, and S-5 Gas Turbines and/or S-2, S-4, and S-6 Heat Recovery Steam Generators. If the highest emission factor for a given pollutant occurs during minimum-load turbine operation, a reduced annual heat input rate may be utilized to calculate the maximum projected annual emissions to reflect the reduced heat input rates during gas turbine start-up and minimum-load operation. The reduced annual heat input rate shall be subject to District review and approval. (TRMP)

Verification: The project owner shall submit to the District and CPM the quarterly and annual compliance reports as required by Condition 25.

AQ-42 Within 60 days of start-up of the EAEC, the project owner shall conduct a District-approved source test on exhaust point P-1, P-2, or P-3 to determine the corrected ammonia (NH_3) emission concentration to determine compliance with condition 25(e). The source test shall determine the correlation between the heat input rates of the gas turbine and associated HRSG, A-2, A-4, or A-6 SCR System ammonia injection rate, and the corresponding NH_3 emission concentration at emission point P-1, P-2, or P-3. The source test shall be conducted over the expected operating range of the turbine and HRSG (including, but not limited to, minimum and full load, and steam injection power augmentation mode) to establish the range of ammonia injection rates necessary to achieve NO_x emission reductions while maintaining ammonia slip levels. Source testing shall be repeated on an annual basis thereafter. Ongoing compliance with condition 25(e) shall be demonstrated through calculations of corrected ammonia concentrations based upon the source test correlation and continuous records of ammonia injection rate. Source test results shall be submitted to the District and the CEC CPM within 60 days of conducting the tests. (TRMP)

Verification: Approval of the source test protocols, as required in condition 16, and the source test reports shall be deemed as verification for this condition. The project owner shall notify the District and the CPM within seven (7) working days before the execution of the source tests required in this condition. Source test results shall be submitted to the District and to the CPM within 60 days of the date of the tests.

AQ-43 Within 90 days of start-up of the EAEC and on an annual basis thereafter, the project owner shall conduct a District-approved source test on exhaust points P-1, P-2, and P-3 while each Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum load (including steam injection power augmentation mode) to determine compliance with Conditions 25(a), (b), (c), (d), (f), (g), and (h), while each Gas Turbine and associated Heat Recovery Steam Generator are operating at minimum load to determine compliance with Conditions 25(c) and (d), and to verify the accuracy of the continuous emission monitors required in condition 39. The project owner shall test for (as a minimum): water content, stack gas flow rate, oxygen concentration, precursor organic compound concentration and mass emissions, nitrogen oxide concentration and mass emissions (as NO_2), carbon monoxide concentration and mass emissions, sulfur dioxide concentration and mass emissions, methane, ethane, and particulate matter (PM_{10}) emissions including condensable particulate matter. Source test results shall be submitted to the District and the CPM within 60 days of conducting the tests. (BACT, offsets)

Verification: Approval of the source test protocols, as required in condition 16, and the source test reports shall be deemed as verification for this condition. The project owner shall notify the District and the CPM within seven (7) working days before the execution of the source tests required in this condition. Source test results shall be submitted to the District and to the CPM within 60 days of the date of the tests.

AQ-44 The project owner shall obtain approval for all source test procedures from the District's Source Test Section and the CPM prior to conducting any tests. The project owner shall comply with all applicable testing requirements for continuous emission monitors as specified in Volume V of the District's Manual of Procedures. The project owner shall notify the District's Source Test Section and the CEC CPM in writing of the source test protocols and projected test dates at least 7 days prior to the testing date(s). As indicated above, the project owner shall measure the contribution of condensable PM (back half) to the total PM_{10} emissions. However, the project owner may propose alternative measuring techniques to measure condensable PM such as the use of a dilution tunnel or other appropriate method used to capture semi-volatile organic compounds. Source test results shall be submitted to the District and the CEC CPM within 60 days of conducting the tests. (BACT)

Verification: Submitting and getting approval of the source test procedures is the verification of this condition. The project owner shall notify the District and the CPM within seven (7) working days before the execution of the source tests required in this condition. Source test results shall be submitted to the District and to the CPM within 60 days of the date of the tests.

AQ-45 Within 90 days of start-up (commercial operation) of the EAEC and on a biennial basis (once every two years) thereafter, the project owner shall conduct a District-approved source test on exhaust point P-1, P-2, or P-3 while the Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum allowable operating rates to demonstrate compliance with Condition 36. The gas turbine shall also be tested at minimum load. If three consecutive biennial source tests demonstrate that the annual emission rates calculated pursuant to condition 39 for any of the compounds listed below are less than the BAAQMD Toxic Risk Management Policy trigger levels shown, then the project owner may discontinue future testing for that pollutant:

Benzene		6.7 pounds/year
Formaldehyde	$\leq$	33 pounds/year
Specified PAHs (TRMP)		0.044 pounds/year

Verification: The project owner shall notify the District and the CPM within seven (7) working days before the execution of the source tests required in this condition. Source test results shall be submitted to the District and to the CPM within 60 days of the date of the tests.

AQ-46 The project owner shall not allow the total combined sulfuric acid mist (SAM) emissions from S-1 through S-7 to exceed 7 tons totaled over any consecutive twelve month period. The SAM emission rate shall be calculated using the total heat input for the sources and the highest results of any source testing conducted pursuant to condition 47. If this SAM mass emission limit is exceeded, the project owner must utilize air dispersion modeling to determine the impact (in g/m^3) of the sulfuric acid mist emissions pursuant to Regulation 2-2-306. (PSD)

Verification: The project owner shall submit to the District and CPM the quarterly and annual compliance reports as required by Condition 25.

AQ-47 Within 90 days of start-up (commercial operation) of the EAEC and on a semi-annual basis (twice per year) thereafter, the project owner shall conduct a District-approved source test on exhaust points P-1 through P-4 while each gas turbine, HRSG duct burner, and auxiliary boiler is operating at maximum heat input rates to demonstrate compliance with the SAM emission rates specified in condition 46. The project owner shall test for (as a minimum) SO_2, SO_3, and H_2SO_4. After acquiring one year of source test data on these sources, the project owner may petition the District to reduce the test frequency to an annual basis if test result variability is sufficiently low as determined by the District. Source test results shall be submitted to the District and the CEC CPM within 60 days of conducting the tests. (PSD)

Verification: The project owner shall notify the District and the CPM within seven (7) working days before the execution of the source tests required in this condition. Source test results shall be submitted to the District and to the CPM within 60 days of the date of the tests.

AQ-48 The project owner of the EAEC shall submit all reports (including, but not limited to monthly CEM reports, monitor breakdown reports, emission excess reports, equipment breakdown reports, etc.) as required by District Rules or Regulations and in accordance with all procedures and time limits specified in the Rule, Regulation, Manual of Procedures, or Enforcement Division Policies & Procedures Manual. (Regulation 2-6-502)

Verification: The project owner shall submit to the District and CPM the reports as required by procedures and time limits specified in the Rule, Regulation, Manual of Procedures, or Enforcement Division Policies & Procedures Manual.

AQ-49 The project owner of the EAEC shall maintain all records and reports on site for a minimum of 5 years. These records shall include but are not limited to: continuous monitoring records (firing hours, fuel flows, emission rates, monitor excesses, breakdowns, etc.), source test and analytical records, natural gas sulfur content analysis results, emission calculation records, records of plant upsets and related incidents. The project owner shall make all records and reports available to District and the CEC CPM staff upon request. (Regulation 2-6-501)

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, EPA or CEC staff.

AQ-50 The project owner of the EAEC shall notify the District and the CEC CPM of any violations of these permit conditions. Notification shall be submitted in a timely manner, in accordance with all applicable District Rules, Regulations, and the Manual of Procedures. Notwithstanding the notification and reporting requirements given in any District Rule, Regulation, or the Manual of Procedures, the project owner shall submit written notification (facsimile is acceptable) to the Enforcement Division within 96 hours of the violation of any permit condition. (Regulation 2-1-403)

Verification: Submittal of these notifications as required by this condition is the verification of these permit conditions. In addition, as part of the quarterly and annual compliance reports of Condition 25, the project owner shall include information on the dates when these violations occurred and when the project owner notified the District and the CPM.

AQ-51 The project owner shall ensure that the stack height of emission points P-1, P-2, and P-3 is each at least 175 feet above grade level at the stack base. (PSD, TRMP)

Verification: 120 days prior to the start of any site clearing or ground disturbance activities, the project owner shall provide the District and CPM an "approved for construction" drawing showing the appropriate stack height and location of sampling ports and platforms. The project owner shall make the site available to the District, EPA and CEC staff for inspection.

AQ-52 The project owner shall ensure that the stack height of emission point P-4 is at least 120 feet above grade level at the stack base. (PSD, TRMP)

Verification: 120 days prior to the start of any site clearing or ground disturbance activities, the project owner shall provide the District and CPM an "approved for construction" drawing showing the appropriate stack height and location of sampling ports and platforms. The project owner shall make the site available to the District, EPA and CEC staff for inspection.

AQ-53 The project owner of EAEC shall provide adequate stack sampling ports and platforms to enable the performance of source testing. The location and configuration of the stack sampling ports shall comply with the District Manual of Procedures, Volume IV, Source Test Policy and Procedures, and shall be subject to BAAQMD review and approval. (Regulation 1-501)

Verification: 120 days prior to the start of any site clearing or ground disturbance activities, the project owner shall provide the District and CPM an "approved for construction" drawing showing the appropriate stack height and location of sampling ports and platforms. The project owner shall make the site available to the District, EPA and CEC staff for inspection.

AQ 54 Within 180 days of the issuance of the Authority to Construct for the EAEC, the project owner shall contact the BAAQMD Technical Services Division regarding requirements for the continuous emission monitors, sampling ports, platforms, and source tests required by conditions 39, 42, 43, 45, and 60. All source testing and monitoring shall be conducted in accordance with the BAAQMD Manual of Procedures. (Regulation 1-501)

Verification: The project owner shall notify the CPM within 7 days of receiving the District's approval for the source testing and monitoring plan.

AQ-55 Prior to the issuance of the BAAQMD Authority to Construct for the East Altamont Energy Center, the Project owner shall demonstrate that valid emission reduction credits in the amount of 302.45 tons/year of Nitrogen Oxides, 84.755 tons/year of Precursor Organic Compounds, and 148 tons/year of PM_{10} or equivalent (as defined by District Regulations 2-2-302.1 and 2-2-302.2) are under their control through enforceable contracts, option to purchase agreements, or equivalent binding legal documents. (Offsets)

Verification: At least 30 days prior to issuance of the District's Authority to Construct, the project owner shall provide valid emission reduction credit banking certificates to the District and the CPM for approval.

AQ-56 Prior to the start of construction of the East Altamont Energy Center, the project owner shall provide to the District valid emission reduction credit banking certificates in the amount of 302.45 tons/year of Nitrogen Oxides, 84.755 tons/year of Precursor Organic Compounds, and 148 tons/year of PM_{10} or equivalent as defined by District Regulations 2-2-302.1 and 2-2-302.2. (Offsets, CEC)

Verification: At least 30 days prior to start of construction, the project owner shall provide valid emission reduction credit banking certificates to the District and the CPM for approval.

AQ-57 Pursuant to BAAQMD Regulation 2, Rule 6, section 404.1, the project owner of the EAEC shall submit an application to the BAAQMD for a major facility review permit within 12 months of completing construction as demonstrated by the first firing of any gas turbine, HRSG duct burner, or auxiliary boiler. (Regulation 2-6-404.1)

Verification: The project owner shall submit to the CPM copies of the Federal (Title IV) Acid Rain and (Title V) Operating Permit within 30 days after they are issued by the District.

AQ-58 Pursuant to 40 CFR Part 72.30(b)(2)(ii) of the Federal Acid Rain Program, the project owner of the East Altamont Energy Center shall submit an application for a Title IV operating permit to the BAAQMD at least 24 months before operation of any of the gas turbines (S-1, S-3, or S-5) or HRSGs (S-2, S-4, or S-6). (Regulation 2, Rule 7)

Verification: The project owner shall submit to the CPM copies of the Federal (Title IV) Acid Rain and (Title V) Operating Permit within 30 days after they are issued by the District.
The samples shall be analyzed for sulfur content using District-

AQ-59 The East Altamont Energy Center shall comply with the continuous emission monitoring requirements of 40 CFR Part 75. (Regulation 2, Rule 7)

Verification: At least 45 days prior to any site clearing or ground disturbance activities, the project project owner shall seek approval from the District for an emission monitoring plan.

AQ-60 The project owner shall take daily samples of the natural gas combusted at the EAEC.
approved laboratory methods. The sulfur content test results shall be retained on site for a minimum of five years from the test date and shall be utilized to satisfy the requirements of 40 CFR Part 60, subpart GG. (cumulative increase)

Verification: The project owner shall submit to the District and CPM the quarterly and annual compliance reports as required by Condition 25.

Permit Conditions for S-8 Cooling Tower

AQ-61 The project owner shall properly install and maintain the cooling towers to minimize drift losses. The project owner shall equip the cooling towers with high-efficiency mist eliminators with a maximum guaranteed drift rate of 0.0005%. The maximum total dissolved solids (TDS) measured at the base of the cooling towers or at the point of return to the wastewater facility shall not be higher than 3,400 ppmw (mg/l). The project owner shall sample and test the cooling tower water at least once per day to verify compliance with this TDS limit. (PSD)

Verification: The project owner shall submit to the District and CPM the quarterly and annual compliance reports as required by Condition 25.

AQ-62 The project owner shall perform a visual inspection of the cooling tower drift eliminators at least once per calendar year, and repair or replace any drift eliminator components which are broken or missing. Prior to the initial operation of the East Altamont Energy Center, the project owner shall have the cooling tower vendor's field representative inspect the cooling tower drift eliminators and certify that the installation was performed in a satisfactory manner. Within 60 days of the initial operation of the cooling tower, the project owner shall perform an initial performance source test to determine the PM_{10} emission rate from the cooling tower to verify compliance with the vendor-guaranteed drift rate specified in condition 61. The CPM may, in years 5 and 15 of cooling tower operation, require the project owner to perform source tests to verify continued compliance with the vendor-guaranteed drift rate specified in condition 61. (PSD)

Verification: The project owner shall submit to the District and CPM the quarterly and annual compliance reports as required by Condition 25.

AQ-63 S-1, S-3, and S-5 Gas Turbines shall each be equipped with air inlet filter(s) and lube oil vent coalescer(s). (BACT for PM_{10})

Verification: One hundred and twenty (120) days prior to start any site clearing or ground disturbance activities, the project owner shall provide the District and CPM an "approved for construction" drawing showing the appropriate air inlet filter and lube oil vent coalescers.

Permit Conditions for S-9 Fire Pump Diesel Engine

AQ-64 S-9 Fire Pump Diesel Engine is subject to the requirements of Regulation 9, Rule 1 ("Sulfur Dioxide"), and the requirements of Regulation 6 ("Particulate and Visible Emissions"). The engine may be subject to other District regulations, including Regulation 9, Rule 8 ("NOx and CO from Stationary Internal Combustion Engines") in the future.

(Regulation 9, Rule 1, Regulation 6)

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, EPA or CEC staff.

AQ-65 The project owner shall ensure that S-9 burns no more than 1,420 gallons of diesel fuel totaled over any consecutive 12 month period for the purpose of reliability-related activities as defined by Regulation 9-8-232. (Offsets, BACT)

Verification: The project owner shall submit to the District and CPM the diesel fuel used in the quarterly and annual compliance reports as required by Condition 25.

AQ-66 The project owner may cause S-9 to burn an unlimited amount of diesel fuel for the purpose of providing power for the emergency pumping of water. (Regulation 9-8-330.1)

Verification: The project owner shall submit to the District and CPM the diesel fuel use in the quarterly and annual compliance reports as required by Condition 25.

AQ-67 The project owner shall equip S-9 with a non-resettable totalizing counter which records fuel use. (cumulative increase)

Verification: 120 days prior to the installation of the fire pump diesel engine, the project owner shall submit to the District and CPM the manufacturer specifications for the fuel meter.

AQ-68 The project owner shall ensure that the sulfur content of all diesel fuel combusted at S-9 does not exceed 0.0015% by weight. (TRMP, TBACT)

Verification: The project owner shall submit to the District and CPM sulfur content of the diesel fuel in the quarterly and annual compliance reports as required by Condition 25.

AQ-69 The project owner shall maintain the following monthly records in a District-approved log for at least 2 years and make such records and logs available to the District upon request:

a) total fuel use for S-9 for the purpose of reliability testing

b) total fuel use for S-9 for the purpose of emergency pumping of water

c) fuel sulfur content

(cumulative increase)

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, EPA or CEC staff.

Permit Conditions for S-10 Emergency Generator

AQ-70 S-10 Emergency Generator is subject to the requirements of Regulation 9, Rule 8 ("NOx and CO from Stationary Internal Combustion Engines") and the requirements of Regulation 6 ("Particulate and Visible Emissions"). (Regulation 9, Rule 8, Regulation 6)

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, EPA or CEC staff.

AQ-71 The project owner shall ensure that S-10 burns no more than 1,150 MM BTU (HHV) of natural gas totaled over any consecutive 12-month period nor 11.5 MM BTU (HHV) of natural gas per day for the purpose of reliability-related activities as defined by Regulation 9-8-232. (Offsets, BACT)

Verification: The project owner shall submit to the District and CPM the quarterly and annual compliance reports as required by Condition 25.

AQ-72 The project owner may cause S-10 to burn an unlimited amount of natural gas for the purpose of emergency use as defined by Regulation 9-8-221. (Regulation 9-8-330.1)

Verification: he project owner shall submit to the District and CPM the quarterly and annual compliance reports as required by Condition 25.

AQ-73 The project owner shall equip S-10 with a non-resettable totalizing counter which records fuel use. (cumulative increase)

Verification: 120 days prior to the installation of the emergency generator, the project owner shall submit to the District and CPM the manufacturer specifications for the fuel meter.

AQ-74 The project owner shall maintain the following monthly records in a District-approved log for at least 2 years and make such records available to the District upon request:

a) total fuel consumption for S-10 for the purpose of reliability testing

b) total fuel consumption for S-10 for the purpose of emergency use

(cumulative increase)

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, EPA or CEC staff.

AQ-75 The project owner shall not operate both S-9 Fire Pump Diesel Engine and S-10 Emergency Generator on the same calendar day for the purposes of reliability-related activities. (PSD)

Verification: The project owner shall submit to the District and CPM the quarterly and annual compliance reports as required by Condition 25.

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